BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

------ In The Matter Of -----)
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PUBLIC UTILITIES COMMISSION) DOCKET NO. 2014-0183
)
Instituting a Proceeding to Review the)
Power Supply Improvement Plans for)
Hawaiian Electric Company, Inc., Hawaii)
Electric Light Company, Inc., and Maui)
Electric Company, Limited.)
)

Hawaiian Electric Companies' PSIPs Update Report

Filed December 23, 2016

Book 4 of 4

O. System Security Analysis

System security (or Operating Reliability) is defined by NERC as *the ability of the system to withstand sudden disturbances*.[1] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

TRANSMISSION SYSTEM FUNDAMENTALS

System security or system stability in an electric power system is the attribute of the system, or its components, to regain a state of operating equilibrium after being subjected to disturbing forces (transient events), such that the majority of the system remains intact. Stability of a power system can be characterized by frequency stability, voltage stability, and rotor angle stability.

The electrical transmission system is designed to deliver power from central station generators to distribution load centers while optimizing efficiency and maintaining a high level of reliability. The transmission system is the backbone of the electrical infrastructure and its design is based on the inherent characteristics of synchronous generators.

A synchronous generator is essentially a large rotating electro-magnet that converts mechanical energy to three-phase electrical energy that is transferred to the electrical system through a rotating magnetic field. All synchronous generators are directly tied to each other through this magnetic field. An electrical system with more synchronous

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[1] NERC, *Definition of "Adequate Level of Reliability"*, December 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

generators (like the Western Electricity Coordinating Council) has a high inertia and a strong magnetic coupling, making it less susceptible to disruptions from disturbances like a generator trip or electrical fault.

Synchronous generators develop balanced, three-phase current in their armature windings with each phase separated by 120°. Generator terminal voltage is increased to higher voltages (for example, 138 kV) to efficiently transfer energy over long transmission lines. Heating losses in a conductor is proportional to the square of the current so increasing voltage by a factor of 10 reduces heat losses by a factor of 100.

Distribution substations reduce the transmission voltage through a step-down transformer so power can be delivered to customers. Distribution circuits attempt balance customer loads maintain this balanced three-phase system to maintain tariff requirements for power quality and ensure system reliability. The challenge is to maintain this balanced three-phase system while integrating high capacities of single-phase DG-PV and demand response resources.

Minimum Fault Current

Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. If the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized "brown-outs" that poses a safety risk to the public and equipment.

Maintaining a minimum level of fault current ensures protective relays will operate. It does not ensure transient voltage stability. An electrical system with a high capacity of fault current is less susceptible to disruptions from electrical faults. Systems with a high fault current capacity are also less susceptible to the adverse effects of harmonic currents. Fault current capacity is supplied by the mega volt-ampere (MVA) capacity of synchronous machines (generators, synchronous condensers, and induction motors).

System Grounding

System grounding is also a fundamental requirement for system security. Unit commitment schedules will have an impact on the available grounding sources on the 138 kV system.

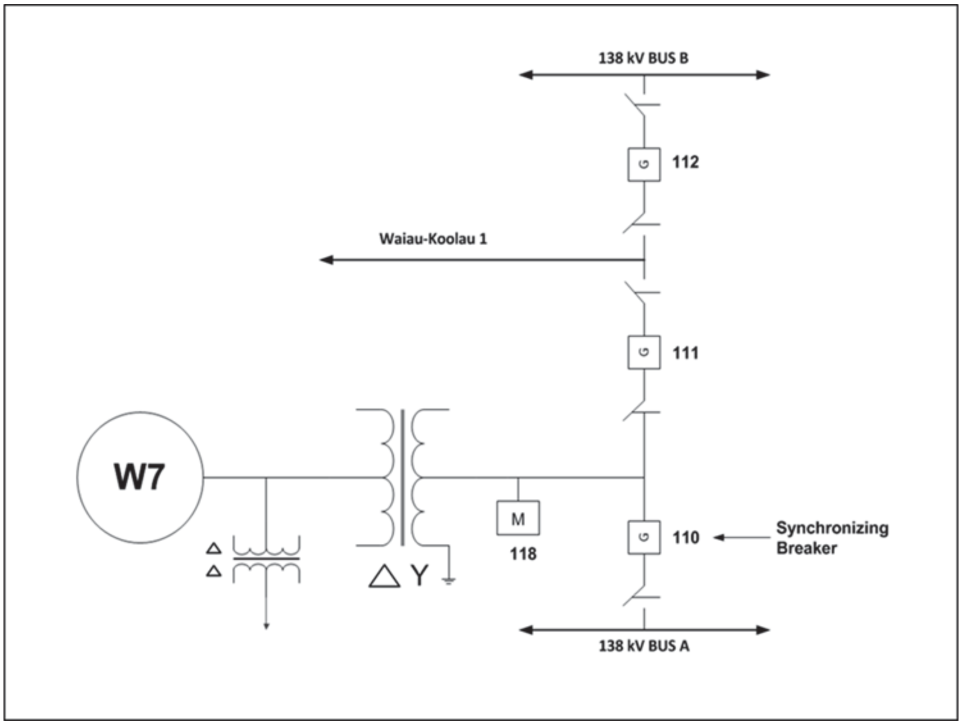

Figure O-1. Grounding Scheme 138 kV System

Figure O-1 shows the single line diagram for Waiau Unit 7 which is typical of all steam units that have synchronizing breakers on the high-side of the step-up transformer. When steam units are cycled offline or decommissioned, the 138 kV grounding source is isolated from the system. The integrity of the 138 kV grounding system must be evaluated in conjunction with the protection coordination study to ensure system security.

System Stability

Whereas previous system security analyses focused on system requirements for frequency stability, this analysis was expanded to determine voltage stability requirements for each resource plan.

Rotor angle stability is an important aspect of system security but this requires unit-specific modeling data like transmission line impedance, generator characteristics (H-constant, synchronous/sub synchronous/transient reactance), exciter characteristics, etc. Given the detailed modeling requirements, rotor angle stability analysis is not feasible for long range planning studies. Rotor angle stability analysis is typically performed as part of the interconnection requirement study for a new facility.

Frequency Stability

Frequency stability is maintained when real power supply is equal to system demand under steady state and dynamic conditions. Frequency instability may occur as a result of a significant loss of generation or load, such that system reserves or protective schemes are unable to return the system to operating equilibrium.

Synchronous generators provide frequency response that is proportional to the magnitude of the contingency event. This includes rotational inertia, that resists changes to rotor speed due to the mass of the turbine-generator rotor; and governor response or primary reserves, that is a reactive, proportional control response to changes in rotor speed. This concept of proportional response is very important as we integrate demand response into the system's frequency response reserves. Over compensation for a loss of generation contingency could drive frequency above 60.5 Hz and cause a subsequent contingency event. The capacity of legacy PV that will disconnect from the system at 60.5 Hz is significantly higher than the capacity that disconnects at 59.3 Hz.

Currently, each island is challenged with maintaining frequency stability on the system. The proliferation of DG-PV has helped the State meet RPS target but at the same time has displaced synchronous generation. Loss of generation on a system with low inertia results in a high rate of change of frequency (RoCoF), making it difficult for traditional governor response to arrest frequency decay.

Voltage Stability

Voltage stability is the ability of a power system to maintain voltages at all buses within specified limits after being subjected to a disturbance from a given initial operating condition, restoring the system to operating equilibrium.

Voltage issues are typically location specific and is a function of loading of the area or bus. Therefore, voltage stability is examined for boundary conditions that represent the highest peak demand for any given year.

The methodology to determine voltage stability included several different steady-state and transient analyses. These include the following:

PV Analysis

The PV analysis is one of the most widely performed analysis to determine the real power transfer capability of the transmission system; and to the determine the active power margin before the point of voltage instability. Multiple power flow simulations are performed for increasing loads while monitoring system voltage.

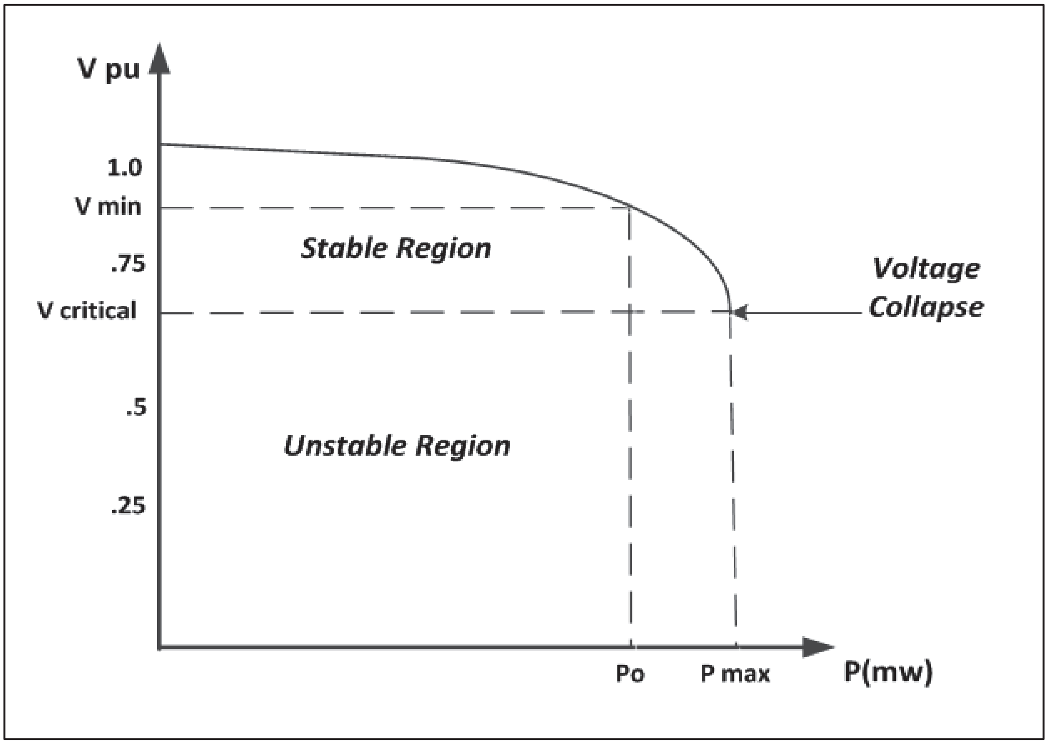

Figure O-2. PV Curve

Figure O-2 shows a typical PV curve. As power flow or load increases, bus voltage begins to decrease until the system reaches the stability limit at *Pmax*. Any increase in load will cause voltage collapse at the bus.

QV Analysis

The QV analysis determines the MVAR requirements of the system to maintain voltage stability under steady state and transient conditions. Critical busses have the lowest per-unit voltage under steady state and post-transient conditions and are selected based on historical data. Therefore, meeting the MVAR requirements for these busses ensures reactive power requirements for the entire electrical system are met.

The QV curve is obtained by plotting the results of a series of power flow simulations where the voltage at the bus of interest is sequentially anchored and the MVARs required to maintain that bus to the anchored voltage is determined. The analysis is performed for a range of per-unit voltages and results plotted to develop the QV curve. A good starting point is bus voltages from 1.0 to 0.85 per unit, anchored in steps of 0.10 per unit.

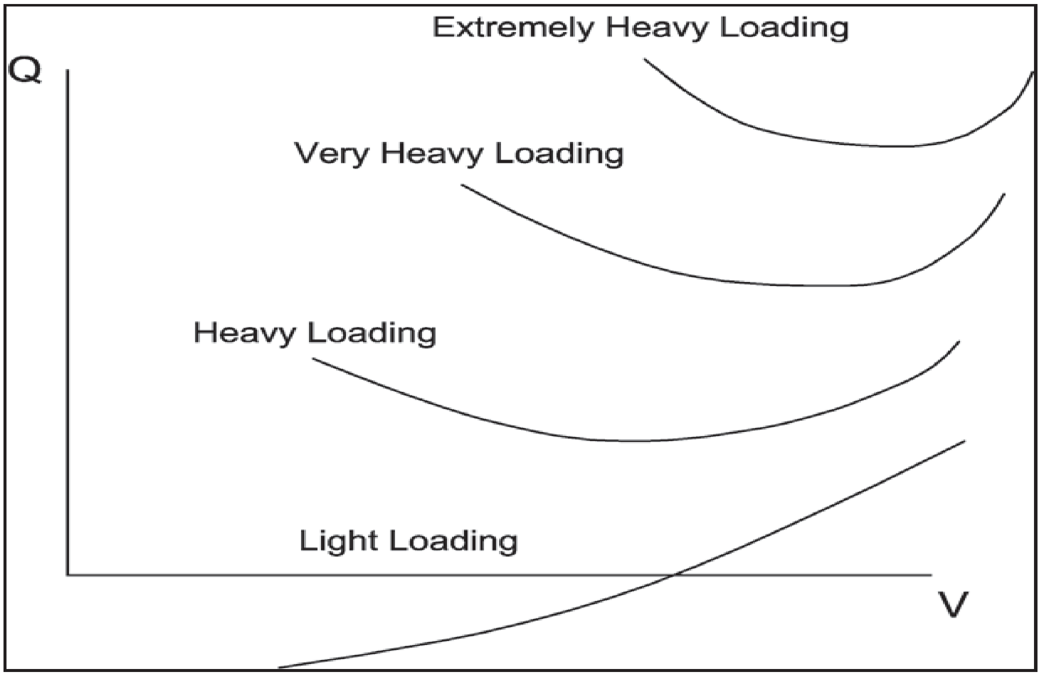

Figure O-3. Family of QV Curves

Figure O-3 shows a family of QV curves at various bus loads. The QV curves at higher loads tend to be parabolic. The bus is stable when the injection of MVARs results in an increase in voltage and unstable at the bottom of the QV curve, where the derivative dQ/dV is equal to zero for the bus under evaluation. In addition to identifying the stability limit of the bus, the bottom of the QV curve defines the minimum reactive power requirement for stable operation. Hence, the QV curve can be used to examine the type and size of compensation needed to provide voltage stability.

Busses having QV curves below the horizontal voltage axis have a positive reactive power margin. The system may still be called reactive power deficient, depending on the desired margin.

Short Circuit Ratio

There is currently no industry-standard approach to calculate the proper short circuit ratio (SCR) index for a weak system with a high penetration of inverter-based generation. To take into account the effect of interactions between wind plants and give a better estimate of the system strength, a more appropriate quantity is the weighted short circuit ratio (WSCR)[2], defined by:

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[2] Electranix, System Strength Assessment of the Panhandle System, Electric Reliability Council of Texas, 2016

$$WSCR = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2}$$

Where S_{SCMVAi} is the short circuit capacity at bus i and P_{RMWi} is the MW rating of the wind plant; N is the number of total wind plants fully interacting with each other and i is the wind plant index. For the purposes of this PSIP analysis, wind plants are replaced with DG-PV capacities.

Several system characteristics and challenges that can occur in a weak grid are:

- In a highly compensated weak grid, voltage collapse can occur within the normal operating voltage range (0.95 to 1.05 PU) masking voltage stability risks in real time operations. Static capacitor and static VAR compensators contribute to this effect and have limited effectiveness for further increasing transfer capability.
- A grid with low short circuit ratios and high voltage sensitivity of dV/dQ requires special coordination of various complex control systems. Typical voltage control settings can result in aggressive voltage support in a weak system and lead to un-damped oscillations, overvoltage cascading or voltage collapse.
- Inverter-based generation connected to a common point of interconnection (POI) may interact with other facilities.

Short circuit ratio analyses will not be performed for this PSIP filing. There is no industry standard that specifies a minimum SCR and specific issues should be evaluated with detailed user models of inverter-based generation at specific bus locations.

Voltage stability analysis for this filing will focus on QV analysis for the near-term Action Plan years through 2021.

Rotor Angle Stability

Rotor angle stability is not part of this system security analysis but is a critical aspect of system security. Rotor angle instability occurs when there is a loss of synchronism of a generator or generator pole slipping.

Special consideration must to given to rotor angle stability because of the potential severe consequences of generator pole-slipping. When a close-in electrical fault cannot be cleared within the critical clearing time of the generator, the magnetic link between the generator and the electrical system is broken, causing loss of synchronism. Consequences can range from no damage to catastrophic failure of both the generator and turbine.

The most severe transient stability incident is the electrical fault that is close to a generating station. Figure O-4 describes what happens when an electrical fault occurs at the generating station bus. Three power angle curves depict pre-fault, during-fault, and post-fault conditions for both stable and unstable operation. The Equal Area Criterion states that kinetic energy that is added to the rotor following a fault must be removed from the rotor after the fault to restore the rotor to synchronous speed. This means that the faulted transmission element must be removed to allow power flow to the system, removing the kinetic energy that was added to the rotor.

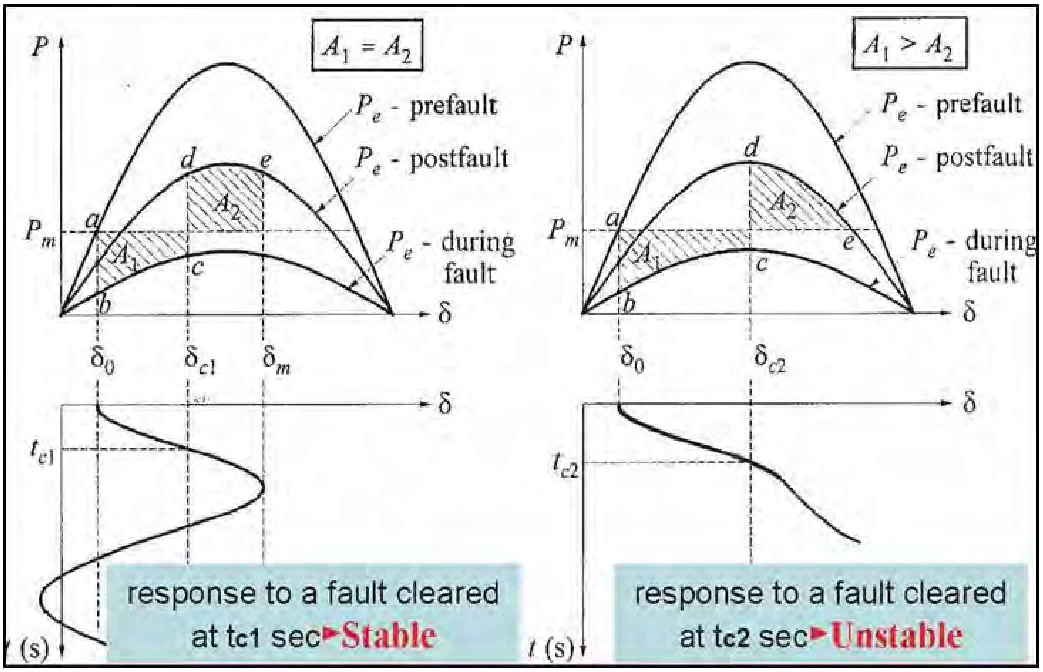

Figure O-4. Equal Area Criterion for Stability

Refer to the power curve plots in the upper left of Figure O-4. The system is operating at "*Point a*" on the "*Pe*-pre-fault" power curve. When the fault occurs, generator terminal voltage will suddenly decrease so there is a drastic decrease in electrical power delivered to the system. The reduction in power delivered to the system is represented by the new power curve "*Pe* – during-fault". The mechanical power remains constant since governor response cannot operate in this timeframe (cycles) and system inertia prevents the power angle $\boldsymbol{\delta_0}$ from changing instantaneously so the system operating point drops to "*Point b*" on the "*Pe* – during fault" curve. Conservation of energy transforms the mechanical energy to kinetic energy so the rotor begins to accelerate (the lower left plot) and the system operating point moves along the "*Pe* – during-fault" power curve to "*Point* ***c***" at which time the fault is cleared at $\boldsymbol{t_{c1}}$. The power angle when the fault is cleared is $\boldsymbol{\delta_{c1}}$.

When the fault clears, generator terminal voltage increases and more power can be delivered to the system. This is depicted by "*Point d*" on the new power angle curve, "*Pe* - post-fault". At this point, kinetic energy that was added to the rotor can be removed (transferred to the system) and the operating point moves to "*Point e*". Note that the rotor continues to accelerate due to inertia and the rotor angle increases until it reaches its maximum rotor angle δ_m. At this time, the rotor angle exhibits a dampening effect as it approaches a state of equilibrium. The fault was cleared in sufficient time to remove the kinetic energy from the rotor and the Equal Area Criteria for stability is met, that is, Area A1 = Area A2.

A similar sequence of events occurs for the power angle curve in the upper right of Figure O-4 except the Equal Area Criteria is not met and the rotor loses synchronism with the system. The electrical fault is cleared at t_{c2}, after the critical clearing time of the rotor. The kinetic energy added to the rotor could not be removed to restore the rotor to synchronism, Area A1 > Area A2.

A system with more synchronous generators has a stronger magnetic coupling, making it more difficult for generators to lose synchronism. In addition, synchronous generators with more rotational inertia (high H-constants) have longer critical clearing times and are better suited to withstand close-in electrical faults. Another factor is the ability of the protective relay system to quickly isolate the faulted element to maintain rotor stability.

Maintaining System Security

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for normal operation, planned contingency events, and cascading contingency events.

Some fundamental design philosophies to ensure system security include the following:

- Limit the magnitude of the contingency (for example, limit the rating of single loss of generation contingency)
- Design requirements of transmission network components (breaker-and-a-half schemes for generating units, redundant transmission lines, multiple transmission corridors, etc.
- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency and under voltage load shed schemes to prevent system collapse

Operational strategies to maintain system security include:

- Commit sufficient synchronous generators and/or synchronous condensers machines to provide inertia for frequency stability; and short circuit current capacity for voltage stability

- Limit the magnitude of the contingency and maintaining adequate contingency reserves are operational strategies implemented by the system operator to maintain system reliability
- Commit units or implement load shifting strategies to mitigate system risk due to transmission line maintenance

SYSTEM SECURITY ANALYSIS

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response. This is why generating units in Hawai‘i are designed to be smaller that units in the mainland. The down side is that generating resources cannot take advantage of economy of scale to lower cost.

Island systems have a fixed load so integration of wind and solar resources displaces traditional synchronous generators. This reduces system inertia, system short-circuit current, and the overall magnetic strength of the electrical system; thus affecting all aspects of system security (that is, frequency stability, voltage stability, and rotor angle stability).

Currently, thermal generators are required to provide all of the system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and/or replace thermal generators. Each candidate resource plan is analyzed to determine technology-neutral system security requirements to meet TPL-001.

Technology-neutral requirements can be determined for frequency response reserves but short circuit current for protective relay schemes and voltage stability can only be provided by synchronous machines. Therefore, resource plans are analyzed to determine if online generators are sufficient to meet minimum short circuit current requirements and if not, synchronous condensers are added to augment thermal unit commitment schedules. Synchronous condensers also provide reactive power capacity and voltage regulation. Therefore, alternatives for these resources like capacitor banks, static VAR compensators, or dynamic VAR compensators were not considered in these analyses.

Reliability Criteria

The HI-TPL-001, along with Transmission Planning Criteria establishes the reliability criteria for each island. For O‘ahu, HI-TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. With no UFLS for single contingency events, O‘ahu is able to leverage DER resources to provide PFR. For Maui and Hawai‘i Island, PFR must be connected to the transmission or sub-transmission systems since DER may be part of the 15% system load shed.

The electrical systems on Moloka‘i and Lana‘i grids are unique radial distribution systems (12kV) that do not fall under the jurisdiction of HI-TPL-001. Therefore, the reliability criterion is to maintain the status quo, if possible, or prevent total system collapse.

Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawai‘i. Under high levels of distributed PV generation, the residential load net of PV is reduced so UFLS schemes are compromised. Instead of disconnecting distribution circuits, future UFLS schemes must incorporate a more surgical (behind-the-meter) residential load shedding scheme or resort to commercial sector load shedding to ensure system security.

In addition to TPL-001, the Transmission Planning Criteria determined the fundamental design of each island's transmission system to ensure distribution systems meet voltages tariff requirements for power quality. For O‘ahu, bus voltages throughout the system must remain above 0.92 PU for N-2 contingencies. For Maui and Hawai‘i Island, bus voltages must remain above 0.90 PU for N-1 contingencies.

How System Security is Typically Maintained

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for planned and contingency events. Some fundamental design philosophies to ensure system security include the following:

- Redundant transmission lines for capacity transfer and contingencies
- Transmission network/spatial integrity of transmission corridors
- Breaker-and- a- half or ring-bus schemes for generating units
- Limit the magnitude of the contingency

- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency load shed schemes to prevent system collapse and reduce restoration times

System security is maintained by operating the system with sufficient inertia, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability.

Inertia: the electrical system includes many rotating components which have inertia, including traditional synchronous generators (large rotating electromagnets coupled to heavy turbines or internal combustion engines), and rotating customer loads (usually induction electrical motors connected to appliances, pumps). During a contingency, the inertia in these rotating mass will resist changes to their rotational speed (that is, limit the rate of change of frequency). Inertia, along with droop response, also provides the dampening characteristic to the frequency response profile following a contingency event as a synchronous generator continuously resists change to its rotational speed. Hence, an electrical system with high inertia is more robust and can withstand contingency events better than a low inertia system.

Operational actions to protect against contingencies: 1) limit the magnitude of the disturbance; 2) reconfigure the system to mitigate risks; and 3) ensure the system is carrying the necessary contingency reserves to mitigate the adverse effects of these contingency events.

Fault protection: synchronous generators provide sufficient system fault current to activate protective relay schemes within the critical clearing times of transmission lines and generators. System fault current is also required to ensure protective relay schemes at the distribution system can detect and isolate downed power lines to ensure public safety and prevent equipment damage. Also note that an electrical system with a high capacity of fault current is less susceptible to the adverse effects of harmonic currents.

How System Security Relates to This PSIP

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response.

For island systems with very high levels of wind and solar resources, the most critical security concern is displacement of thermal generators, reducing system inertia and the available system fault current.[3] This concern dominates because (a) the largest loss of generation contingency becomes a larger percentage of the total supply; (b) the large contingency on the low inertia system will require multiple blocks of under frequency load shed (UFLS) to stabilize system frequency; and (c) displacement of synchronous generators reduce the magnetic strength of the system.

System security considerations are incorporated into this PSIP plan in a supportive role and do not constrain the candidate resource plans beyond limiting the magnitude of the contingency as stated above. Currently, thermal generators provide the necessary system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and replace these attributes.

Each candidate resource plan is analyzed to determine system security requirements to 1) meet the reactive power requirement of the system, and 2) meet the requirements of TPL-001. Frequency response reserve capacities are determined for each resource plan in technology-neutral capacities and reactive power requirements are met by synchronous condensers.

APPROACH TO ANALYZING SYSTEM SECURITY IN THIS PSIP

The process of identifying needs and designing solutions follows a several-step process that we believe addresses the Commission's concerns regarding the prior PSIP filing. (Note that this process was outlined as six steps in the Companies' February 2016 filing. The revised process is equivalent, but reorganized to complement the rest of the PSIP more clearly.)

The five steps are:

- Establish operational reliability criteria.
- Define technology-neutral ancillary services for meeting reliability criteria.
- Determine system requirements to support the resource plan.
- Find the lowest reasonable cost solution, considering all types of qualified resources.
- Identify flexible planning and future analyses to optimize over time.

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[3] Low short-circuit current also affects transient voltage stability and harmonics.

Step 1: Establish Reliability Criteria

Two documents establish the reliability criteria for this system security analysis. In addition to TPL-001, Oʻahu, Maui, and Hawaiʻi have Transmission Planning Criteria that established the foundational design of each island's transmission system.

For Oʻahu, TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawaiʻi Island allow 15% system load. The Molokaʻi and Lanaʻi systems are nominal 34.5/12 kV radial distribution systems that do not fall under the jurisdiction of TPL-001. The reliability criteria for these system is to maintain an acceptable margin of stability to ensure public safety and meet tariff obligations for power quality.

Step 2: Define Technology-Neutral Requirements for Meeting Reliability Criteria

The fundamental system security requirements can be defined by segregating the frequency response characteristics inherent to synchronous generators. These include the following:

Inertia is required to resist changes to the rotational speed of generators. A system with higher inertia is less susceptible to disruption due to disturbance cause by an imbalance of generation and load; and is more likely to regain a state of operating equilibrium. Inertial response is proportional to the magnitude of the contingency and is specified in MW-sec or Megajoules.

Primary frequency response (turbine governor or droop response) is required to reduce the rate-of-change of frequency and stabilize system frequency (obtain a state of operating equilibrium) following a generation to load imbalance. Primary frequency response is proportional to the magnitude of the contingency and is specified in a MW capacity for a given droop response (e.g. 5%).

Fault current or short circuit current capacity is determined by the capacity of synchronous generating units and to some extent, induction motors. Analogous to inertia and frequency, a system with higher fault current is less susceptible to disruption due to disturbances due to electrical faults. For this analysis, minimum fault current capacity required to operate protective relays does not ensure transient voltage stability of the system. Fault current is specified in MVA and is supplied by synchronous generators or synchronous condensers.

Reactive power provides the energy to magnetize the system, e.g. transformer windings, inductive circuits and coils, motor stator windings, conductor losses, etc. Reactive power is specified in MVAR and is supplied by synchronous generators and synchronous condensers.

Fast frequency response is an ancillary service product and is not an inherent characteristic of synchronous generators. Fast frequency response limits the rate-of-change of frequency, providing more time for primary frequency response to stabilize system frequency.

Table O-1 presents the frequency response services proposed for Hawaiʻi, along with technical specifications that any resource type would have to meet in order to provide that service.

Frequency Response: Services		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
Inertia	Resist changes to rotational speed of synchronous units	
■ Synchronous generators (including pumped storage) and flywheels ■ Synchronous motor loads also provide inertia; Hawaiian Electric may plan around them but wouldn't procure or control them ■ Synchronous condensers	■ Spinning mass electromagnetically coupled to grid	■ Natural characteristics of synchronous generators ■ Proportional response to changes in speed
Primary Frequency Reserves (PFR)	Stabilize frequency in either direction w/response proportional to changes in speed or frequency	
■ Synchronous generators ■ Inverter-interfaced generators and storage	■ Governor or control system meeting minimum performance requirements for droop and deadband	■ Initiation governed by deadband less than ± 1Hz ■ Linear response to changes in speed or frequency ■ Time to max: a few seconds (for example, 16 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time
Fast Frequency Reserves 1 (FFR1)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Very fast-response resources (likely central station), such as batteries, flywheels, and curtailed PV	■ Control system capable of responding to signals within specified response time ■ 2-way real-time communications	■ Trigger: signal from large trip or df/dt ■ Initiation time and time to max: several cycles (for example, 12 cycles total reaction time) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 10 minutes in ERCOT; 30 minute in Hawaiʻi Electric Light to allow replacement by gas turbine.)
Fast Frequency Reserves 2 (FFR2)	Reduce the rate of change of frequency w/response that is independent of generation contingency	
■ Distributed resources w/autonomous control, including DR from fairly constant loads that can curtail nearly instantaneously	■ Under-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much load is available to curtail	■ Trigger: 59.7 Hz ■ Initiation time (and time to max): a fraction of a second ■ Duration: TBD based on Replacement response time and DR capabilities (for example, 1 hour in ERCOT FAS)

Table O-1. Frequency Response: Services

Step 3: Determine System Requirements to Support the Resource Plans

System security requirement vary with each resource plan vary by island, resource strategy, and time period. That is because Frequency Response needs are driven by the size of the largest contingency, which is generally the largest unit online at the time. Regulation needs are driven by the variability of net load (that is, load minus renewable generation output), which depends especially on the amount of PV and wind. And Replacement reserve needs are driven by the amounts of Frequency Response and Regulation needed.

Reactive Power Requirements. QV analyses were performed on critical busses to determine if the resource plans meet the reactive power requirements of the system to ensure voltage stability. The QV analysis was performed for N-2 transmission contingencies for O‘ahu, and N-1 transmission contingencies for Maui and Hawai‘i Island.

Frequency Response Requirements. Our analytical methodology for determining the necessary amounts of Frequency Response services builds upon the FFR analyses performed in the Integrated Demand Response Portfolio Plan Supplement: System Response Requirements dated November 6, 2015 (Docket No. 2007-0341). In this PSIP, Fast Frequency Reserve requirements are determined for selected years for each candidate resource plan, under a range of system inertia, system load, and PFR for the largest contingency. The specific modeling approach and key assumptions are described in the next section of this appendix.

Minimum Fault-Current. Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. However, if the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized "brown-outs" could trigger extensive UFLS. This also poses a safety risk to both equipment and the public.

Simulations were performed in the April PSIP to determine the MVA capacity required to meet minimum fault current levels for three phase, line-to-line, and single line to ground faults are established for each substation 46kV bus to ensure proper operation of protective relay schemes.

For the Maui and Hawai‘i Island systems, the minimum fault current requirements at the distribution substations have not been determined. Therefore, the MVA capacities provided by the current must-run thermal units will be maintained.

Step 4: Find Lowest Reasonable Cost Solution Considering All Types of Qualified Resources

All of the Ancillary Service needs are defined in technology-neutral terms so any qualified resource can meet them, whether traditional generation, advanced features of inverter-interfaced generation and storage, or demand response. Our objective is to identify the lowest reasonable cost combination that ensures system security for a given resource plan and in subsequent iterations, let the market and specific resource applications determine available resources. To do so, we break the analysis into three steps:

1. Perform analysis on pre-DR resource plans to determine system security requirements;
2. Substitute DR to the full extent it is cost-effective, producing a revised resource strategy;
3. Perform analysis on DR resource plans to determine system security requirements.

As stated earlier, thermal units are required to provide system fault current from 2016 through a period of time when retired units can be converted to synchronous condensers as dictated by the resource plan. To reduce potential curtailment in the interim, fossil fired steam units can operate in in VPO[4] if available.

In the pre-DR solution, we determine what is required to meet HI-TPL-001. We then determine if FFR2 capacities are sufficient and if not, evaluate alternatives to meet system security requirements. This could be to limit the magnitude of the contingency, supplement FFR2 with increased system inertia (operate units in VPO if available), or supplement FFR2 with FFR1.

The initial pre-DR solution meets Regulation needs from the lowest-cost available resources by including regulation as a minimum "spinning reserve" constraint in the dispatch model. If not enough regulation is available, batteries or other resources are added. Note that these needs have already been met before determining Frequency Response needs and solutions.

Once we have a pre-DR solution that meets system security, we determine how much DR can meet the AS technical requirements and cost-effectively substitute for the pre-DR resources.

Finally, after having added DR and other resources to support system security, we assess whether another iteration of system security analysis is warranted. For example, if the amount of synchronous generation decreases substantially, more FFR or system inertia may be needed.

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[4] Variable Pressure Operation entails partial burner operation with lower operating pressures. This lowers the operating load at the expense of lower or negligible reserve capacities for dispatch.

Step 5: Identify Flexible Planning and Future Analyses to Optimize Over Time

The PSIP provides a framework to support future decision-making, not a set-in-stone plan. It recognizes the need for flexibility. It recognizes that actual future procurement decisions will incorporate new information and sharpen specific analyses that are not practical or appropriate for the PSIP. But the PSIP can identify ways to maintain flexibility, and future developments to look for, and some of the analyses to conduct when decisions have to be made.

Future analyses may include the following:

- Short circuit ratio analysis to determine the minimum short circuit current required to maintain transient voltage stability.
- Steady state load flow and transient analysis tools to transmit DER to the transmission system
- Damping of oscillatory instabilities for a low-inertia system. Siemens PSS/E is limited to point in time contingency events and is not suited to analyze instability caused by frequency oscillations
- Power quality impacts to the transmission system
- Smart inverter controls and characteristics required to meet system security
- Effects of Rapid Transit in O‘ahu
- Some of these analyses will require modeling tools and/or outside support.

MODELING ANALYSIS

For the April filing, simulations were performed using Siemens PSS/E Version 33.4 software. The generic inverter-based models for these analyses were released in Siemens PSS/E Version 33.7 to facilitate new DG-PV models. System models for each island have been validated against actual events to ensure a high level of confidence in the simulated results for these analyses.

As with any modeling application, each has its benefits and limitations. Siemens PSS/E software is designed to simulate a strong electrical grid, i.e. a grid with a $SCR > 3$. The issue with violating this criterion is that generic inverter-based generator models may be unstable for both small and large perturbations. These models were developed by WECC for a minimum $SCR \geq 3$ at the point of interconnection of the generators. Therefore, what might appear to be an unstable system could be a mathematical problem with the models.

Distributed Generation PV Models

For the April filing, DG-PV was modeled as a negative load on each load bus on the system. This essentially reduced the total net load supplied at the load bus. Two negative load models were created to represent legacy PV inverters and subsequent PV systems with extended ride-through settings. A complete table of the modeled ride-through settings is provided below.

Type	Legacy		Extended	
	Range	Trip (sec)	Range	Trip (sec)
Frequency	-	-	$f > 64$	0.1667
	-	-	$f > 63$	20
	$f > 60.5$	0.157	-	-
	$f < 59.3$	0.157	-	-
	-	-	$f < 57$	20
	-	-	$f < 56$	0.1667
Voltage	$V > 1.2$	0.157	$V > 1.2$	0.1667
	$V > 1.1$	0.99	$V > 1.1$	0.92
	$V < 0.88$	1.99	$V < 0.88$	20
	-	-	$V < 0.7$	10
	$V < 0.5$	0.157	$V < 0.5$	0.5

Table O-2. Negative Load Ride-Through Settings

For this filing, DG-PV is modeled as three inverter-based generators connected to each load bus on the system. The three generators represent 1) legacy PV, 2) reprogrammed legacy PV, and 3) full ride-through DG-PV. Modeling the characteristics of different vintages of DG-PV allows the dynamics and protection settings of each DG-PV type to be modeled in greater detail. Table O-3 below shows the ride-through settings for the different DG-PV models. A custom user-written generator protection model was developed to consolidate all protection settings into one model per machine.

Type	Legacy		Reprogrammed		Full	
	Range	Trip (sec)	Range	Trip (sec)	Range	Trip (sec)
Frequency	-	-	-	-	$f > 64$	0.1667
	-	-	-	-	$f > 63$	20
	$f > 60.5$	0.157	$f > 60.5$	0.157	-	-
	$f < 59.3$	0.157	-	-	-	-
	-	-	$f < 57$	0.157	$f < 57$	20
	-	-	-	-	$f < 56$	0.1667
Voltage	$V > 1.2$	0.157	$V > 1.2$	0.157	$V > 1.2$	0.1667
	$V > 1.1$	0.99	$V > 1.1$	0.99	$V > 1.1$	0.92
	$V < 0.88$	1.99	$V < 0.88$	1.99	$V < 0.88$	20
	-	-	-	-	$V < 0.7$	10
	$V < 0.5$	0.157	$V < 0.5$	0.157	$V < 0.5$	0.5

Table O-3. Inverter-based Generator Ride-Through Settings

As recommended by Siemens consultants, the GE PV (GEPVG) custom user-written model is being used to model the dynamic response of all DG-PV generators.

Grid-Scale Wind and PV Models

For existing grid-scale wind and PV generators, user-written models provided by developers are used with contract ride-through settings. Future grid-scale wind and PV generators are modeled with the generic renewable energy generator/converter model (REGCAU1) and generic electrical control models for wind and large-scale PV (REECAU1/REECBU1). Ride-through settings for future grid-scale wind and PV generators use the full ride-through settings in Table O-3 above.

Modeling Assumptions

The following assumptions are common across cases:

- The kinetic energy for each generator was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. For the system, the total kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.
- Loads are modeled to have frequency dependence. A load frequency characteristic exponent of 2 translates to a 2% decline in real power consumption for a 1% drop in frequency. For example, in a 1000 MW system, load will decrease by 20 MW for a system frequency of 59.4 Hz, a decrease of 0.6 Hz. This relationship is attributed to the makeup of the system load, with a portion of it consisting of motor loads. The frequency response from motor loads is typically one to two percent of load.

- Legacy PV inverters have a frequency range of 59.3 Hz to 60.5 Hz. The table below shows the assumptions made as to the amount of inverters that still have these frequency ranges. These figures were estimated by the Companies based on a review of the inventory of installed inverters and what ride-through standards applied to these inverters. If a contingency drives system frequency outside of this range, inverters are required to disconnect from the system within 0.16 seconds (for simplicity, legacy PV is modeled to immediately trigger disconnect with inverter time delays). The capacity of legacy PV that would disconnect at 60.5 Hz is higher than the capacity that at 59.3 Hz, as shown in Table O-4 below. In the simulations, the amount of PV generation lost is less than the nameplate capacity to the extent that PV capacity factors are below 100% for the simulated hour. All other DG-PV will continue generating if frequency remains between 56 Hz to 64 Hz and voltage remains above 0.5pu.

Legacy PV Capacities					
Island	O'ahu	Hawai'i	Maui	Moloka'i	Lana'i
Size PV Systems (kW) @ 59.3 Hz	73,499	7,940	7,205	1,100	96
Size PV Systems (kW) @ 60.5 Hz	215,878	56,600	76,656	1,100	464

Table O-4. Legacy PV Capacities

The focus of the frequency response analyses are on the system's first-swing stability. Although simulations can run for 10-20 seconds, we do not simulate automatic generation control (AGC) interaction following a contingency event. If system frequency exceeds a given deadband, e.g. 59.5 Hz, AGC will dispatch all generators within it control cycle of 2-seconds. Therefore, under frequency load shed kicker blocks that are designed to activate in 10 seconds were disabled.

To simulate the performance of autonomous-controlled inverter-based systems, DER resources are modeled with droop response to simulate frequency-watt functionality. Droop response is inversely proportional to the system’s frequency response profile so this resource would be characterized as PFR.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6.

Fast frequency response two (FFR2) was modeled as a load shed block that is triggered at 59.7 Hz to simulate Demand Response load control technology in the near future. For both FFR1 and FFR2, we assumed these capacities are available until supplemental reserves can restore system frequency to 60 Hz. Otherwise, loss of this capacity could trigger a secondary contingency event.

Limitations of Modeling Simulations

As with any modeling simulation, the dynamic performance of transmission system components, especially generating resources, cannot be accurately captured in a model. Dynamic models are a critical component of these analyses. Governor and exciter models with default settings are adequate for simulating system contingency events when many units are running. As traditional synchronous generation is displaced, more sophisticated and accurate, dynamic models will be required to ensure confidence in simulation results. Complex dynamic load models will also be required to better understand load impacts on voltage stability.

Production cost simulation models optimize system performance with perfect foresight and cannot take into account operational changes to mitigate system risks. For example, system operators may commit non-economic units to mitigate system risks when transmission lines are taken out of service for maintenance.

Screening Tool Improvements

For the April filing, a single-bus network model was developed in PSS/E that allows us to perform dynamic loss of generation simulations for every hour in selected years, using the production cost simulation output to determine the dispatch. For each hour, the screening tool calculated the frequency nadir for a generation trip of the largest online resource. Based on the results of the screening tool, two informative hours (boundary hour and typical hour) are selected for further detailed analysis. The comprehensive analysis uses the full network PSS/E model to determine the frequency response reserve requirements to meet TPL-001.

Subsequent to the analysis performed for the April PSIP filing, the following improvements were made to the screening tool:

- Calculates FFR1 requirement for each hour in the study year
- Ability to use a FFR2 hourly profile as an input
- Incorporates future resources such as GE 151MW combined cycle, pumped storage hydro, and load shifting storage
- Improvements to the UFLS implementation
- Calculates total MVA of online synchronous generation, to check if resources meet fault current requirements
- Adjustments to the methodology on determining if a generating unit is on or off
- Ability to accept Plexos hourly output data as input to the tool

In additions to the above improvements to the screening tool after the April filing, the methodology in selecting the “boundary” and “typical” hours was slightly modified. For the April filing, the "boundary hour" was the hour with the lowest frequency nadir. With the improvement in the screening tool to calculate FFR1 requirement, the “boundary hour” was selected based on highest FFR1 requirement from the group of hours with the severest UFLS block tripped. This would represent a very high impact contingency but with a lower probability of occurrence. The "typical hour" represents an impact that may not be as significant but the probability of occurrence is higher. For O‘ahu, the “typical hour” was selected based on the largest weekday hour FFR1 requirement from a severe frequency range with about 800-1000 hours occurrence. For Hawai‘i and Maui, the “typical hour” was selected based on the largest FFR1 requirement from a weekday daytime hour with less blocks shed than the “boundary hour”. If screening analysis did not produce sufficient hours, only a boundary hour was selected and analyzed.

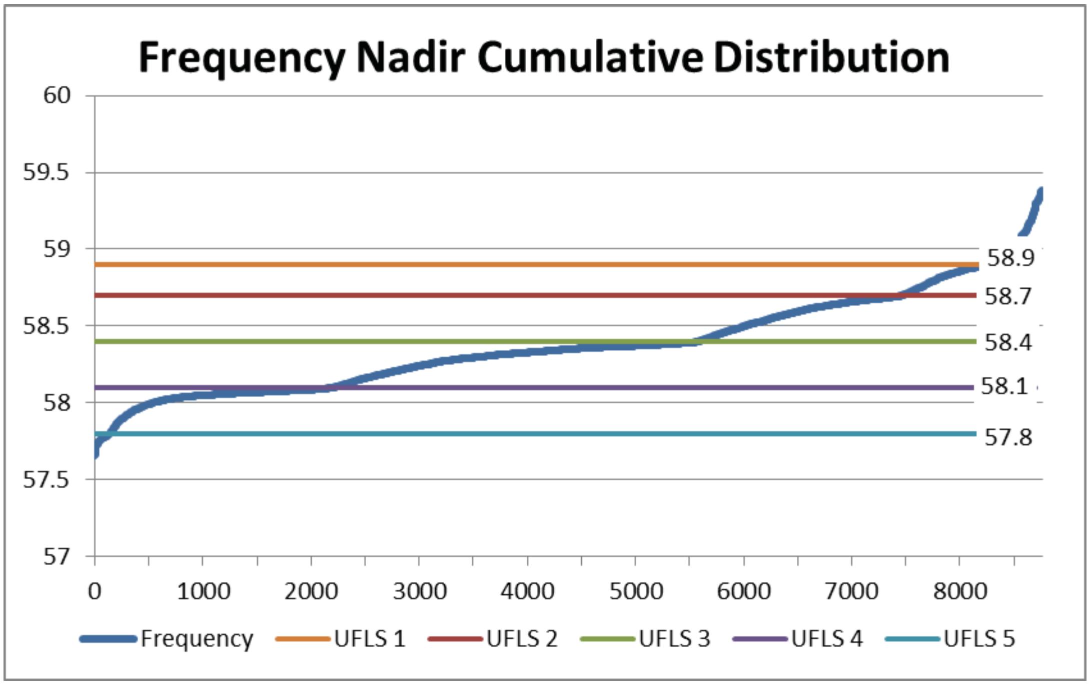

Figure O-5. Frequency Nadir Duration Curve

Figure O-5 shows the duration curve of the frequency nadirs for all the hours in 2023. The horizontal lines show the UFLS blocks for O‘ahu. The example chart above shows the system's exposure to tripping one block of UFLS is approximately 8,000 hours of the year. Furthermore, the system is at risk of requiring four blocks of UFLS (58.1 Hz) for 2000 hours of the year.

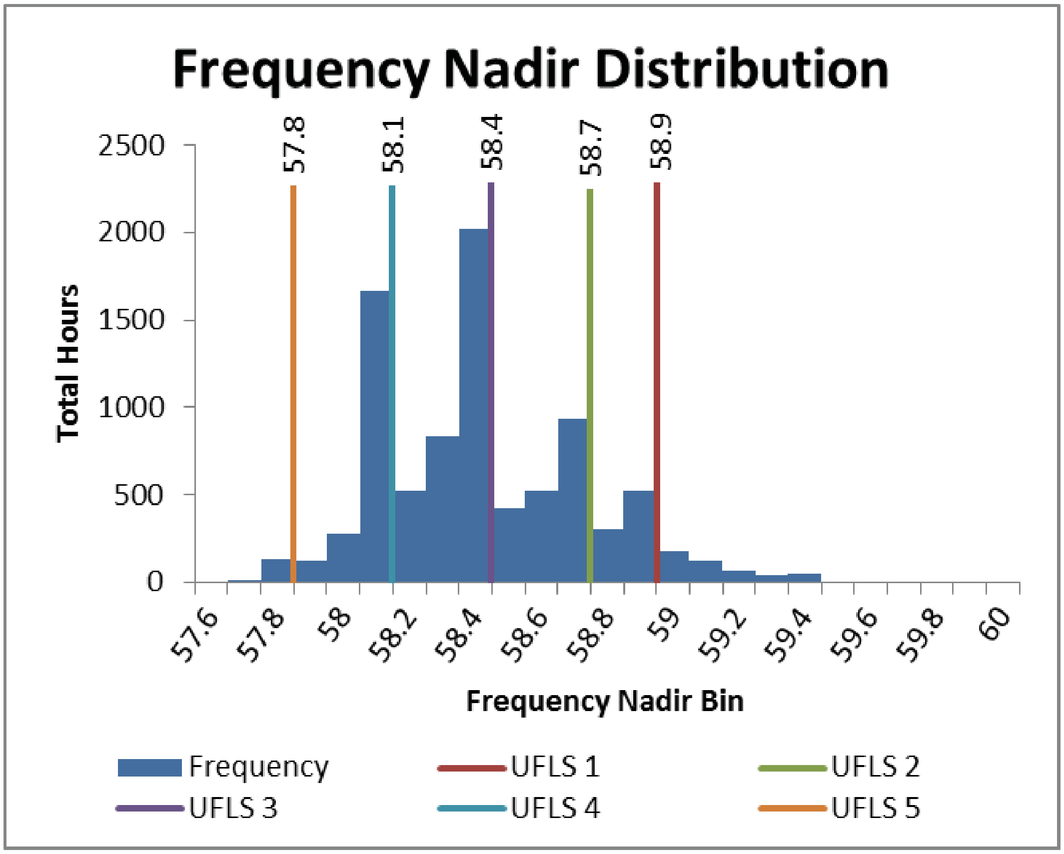

Figure O-6. Frequency Nadir Histogram

Figure O-6 shows the hourly distribution of the frequency nadirs as a result of loss of generation contingency events for 2023. The same source data for the chart above was used to generate this chart, which grouped the nadir data in 0.1Hz frequency buckets.

Using the frequency nadir distribution chart, two hours are selected for further analysis using the full PSS/E system model. The first hour is chosen by selecting a severe nadir from a large frequency grouping that can occur more frequently in the year (large bar on graph, with significant blocks load shed).

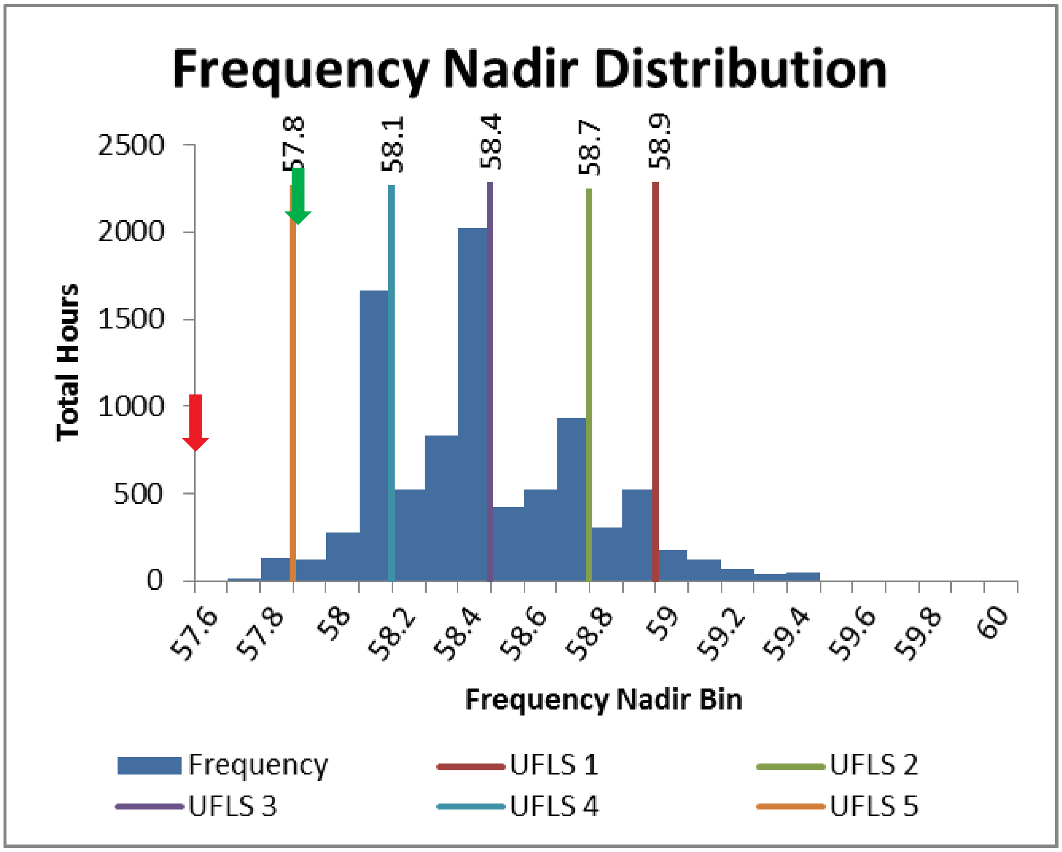

Figure O-7. Frequency Nadir Histogram – Selection

Figure O-7 illustrates the selection of hours for more detailed analysis. The green arrow represents a typical hour for a range of frequency nadirs from 58.0 - 58.1 Hz that could occur 1636 hours in 2023. The red arrow represents a boundary hour for a range of frequency nadirs from 57.6 - 57.8 Hz that could occur 129 hours in 2023. The selected hours are further analyzed using the comprehensive PSS/E database.

O‘AHU SYSTEM SECURITY ANALYSIS

State of the System

The O‘ahu system does not meet the requirements of TPL-001. The proliferation of DG-PV poses the biggest challenge to system security because it imposes fundamentally conflicting requirements on the electrical system; 1) the reduction of system load displaces synchronous generators and 2) DG-PV increases regulating and contingency reserve requirements that are traditionally provided by synchronous generators.

More specifically, transformation of the electrical system must address the following system security issues:

- DG-PV displaces synchronous generators that provide essential grid services like inertia, regulating reserves, and system fault current
- DG-PV reduces the capacity of the system's under frequency load shed scheme (UFLS)
- Legacy DG-PV increases the magnitude of a loss of generation contingency
- DG-PV is currently an uncontrollable and invisible resource

The design of an electrical system is based on the inherent characteristics of synchronous generators. A synchronous generator is basically a large rotating magnet that provides essential grid services like inertia and fault current to the system; two critical parameters required to maintain system stability. As synchronous generators are cycled offline to make room for as-available resources, the stability margin of the system is reduced and we begin to approach the stability limits of the system.

Besides the loss of these stability parameters, lower daytime loads increases the magnitude of the generation contingency. Prior to the proliferation of DG-PV, an AES trip at full output typically represented 15 – 18% of the system generation. Today, an AES trip combined with loss of generation from legacy PV can represent 30% - 35% of the typical daytime load, doubling the magnitude of the contingency event.

Lower system inertia and the larger magnitude contingency increases the rate of change of frequency (RoCoF), reducing the time for traditional governor droop and demand response to arrest the decay in system frequency. Analysis of recent AES trip events confirms that O‘ahu’s electrical system is operating with a smaller stability margin and is relying on multiple blocks of UFLS to help stabilize system frequency.

The UFLS scheme is designed to stabilize system frequency for severe loss of generation contingency events and is a last-resort system preservation scheme to prevent an island-wide blackout. Under frequency load shed schemes are implemented in blocks of load that are coordinated to shed increasing amounts of load at various frequency settings, progressively increasing the amount of load shed for larger contingency events. The intent is to preserve the system for the low probability/high impact contingency events or unforeseen cascading events.

The initial blocks of UFLS target residential load and avoids critical loads like hospitals, emergency responders, department of defense facilities, schools, commercial sectors, etc. Unfortunately, the proliferation of DG-PV is primarily on these residential distribution circuits so the daytime UFLS capacities for Blocks 1-3 continue to degrade; making it difficult to maintain adequate load capacities and coordination.

Minimum Fault Current Analysis

O‘ahu is the only system that has established a minimum fault current requirement based on analysis. Simulations were performed for three phase-to-ground, two phase-to-ground, single phase-to-ground, and line-to-line faults for different unit commitment schedules while monitoring 46kV bus currents. Units were cycled offline until one or more of the Minimum Acceptable Fault Current Limits from Table O-5 were violated.

46kV Circuit		3LG Fault	2LG Fault	1LG Fault	LL Fault
Circuit Name	*Circuit Breaker*	*Fault Current (Amps)*	*Fault Current* (Amps)*	*Fault Current (Amps)*	*Fault Current (Amps)*
Halawa 1	4865	2834	2665	2242	2451
Halawa 2	4864	2704	2492	2068	2338
Halawa 3	4863	2596	2370	1901	2245
Halawa 4	4883	2894	2677	2247	2503
School - Puunui	4582	8366	8062	7154	7217
School - Nuuanu	4409	7034	6570	5565	6071
Iwilei 1	4401	5476	4966	3751	4730
Iwilei 2	4402	6375	5805	4577	5504
Koolau - Kahuku	4464	1002	925	600	868
Koolau - Wailupe 1	4467	1832	1659	1186	1587
Koolau - Wailupe 2	4477	1926	1737	1245	1668
Koolau - Aikahi	4465	2599	2368	2014	2251
Koolau - Kaneohe	4466	2220	2022	1561	1922
Koolau - Nuuanu - Laelae	4484	2633	2436	2056	2280
Koolau - Pohakupu	4469	2095	1894	1409	1814
Koolau - Kailua	4414	2027	1842	1385	1755
Pukele 1	4813	3115	2945	2649	2695
Pukele 3	4815	2732	2527	2119	2364
Pukele 5	4820	2497	2285	1823	2160
Pukele 6	4817	2373	2164	1696	2054
Pukele 7	4818	2806	2592	2176	2428
Pukele 8	4819	3040	2844	2475	2630
Makalapa 42	5133	4816	4425	3516	4164
Makalapa 46	5128	5730	5549	4860	4952
Wahiawa - Waialua 2	4683	921	352	512	797
Wahiawa - Milikua	4621	1433	683	927	1240
Wahiawa - Mililani	4448	2814	1931	2289	2434
Wahiawa - Waimano	4449	2048	1082	1417	1772
Kahe - Mikilua	4714	1708	1042	1293	1478
Kahe - Standard Oil 1	4717	2541	1978	2489	2182
Kahe- Standard Oil 2	4715	1693	1025	1276	1465
Kahe - Permanente	4716	2205	949	1290	1855
CEIP 42	5156	3224	3003	2618	2788
CEIP 45	5159	3264	3051	3473	2798
CEIP 46	5160	2441	2160	1461	2046
Ewa Nui 41	5338	2646	2427	1951	2288
Ewa Nui 42	5339	2843	2660	2247	2459
Waiau - Steel Mill	4653	2655	2412	1659	2297
Waiau - Barbers Point	4486	3994	3627	2793	3452
Waiau - Mililani	4453	1748	1655	1122	1513
*Highest Phase Current					

Table O-5. Fault Current Requirements

Table O-5 lists the minimum fault current requirements for each 46 kV bus. To meet the minimum fault current requirements, 515 MVA of synchronous units must be online on the 138 kV system. Any combination of synchronous generating units or synchronous condensers will suffice. Synchronous machines at the 46kV sub-transmission level must be analyzed because of the impedance of the 138-46kV transformers.

Resource plans are screened to determine if the unit commitment schedule violates the 515 MVA requirement. If the violation occurs for less than 200 hours per year, units can be committed in VPO to meet the fault current requirement. Otherwise, synchronous condensers are required to maintain system security without significantly impacting system operating cost or renewable energy curtailment.

Historical Contingency Events

O'ahu has experienced several AES trip events over the past two years that required multiple blocks of UFLS to stabilize system frequency. On June 9, 2014, AES experienced a turbine trip at full output that resulted in an effective loss of 198 MW. With the additional loss of 50 MW of generation from Legacy PV, the contingency event was 248 MW that represents a 30% loss of generation. The system was carrying 310 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in less than 3 seconds. Three blocks of UFLS (approximately 110 MW) were required to stabilize system frequency.

On July 22, 2015, AES experienced a turbine trip at full output that resulted in an effective loss of 201 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 256 MW that represents a 29% loss of generation. The system was carrying 283 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in 3.25 seconds. Three blocks of UFLS (approximately 82 MW) were required to stabilize system frequency.

On July 23, 2015, AES experienced a breaker trip at full output that resulted in an effective loss of 180 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 235 MW that represents a 28% loss of generation. The system was carrying 297 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.5 Hz in less than 3 seconds. Three blocks of UFLS (approximately 82 MW) were required to stabilize system frequency.

Figure O-8 shows the frequency response profiles of these events.

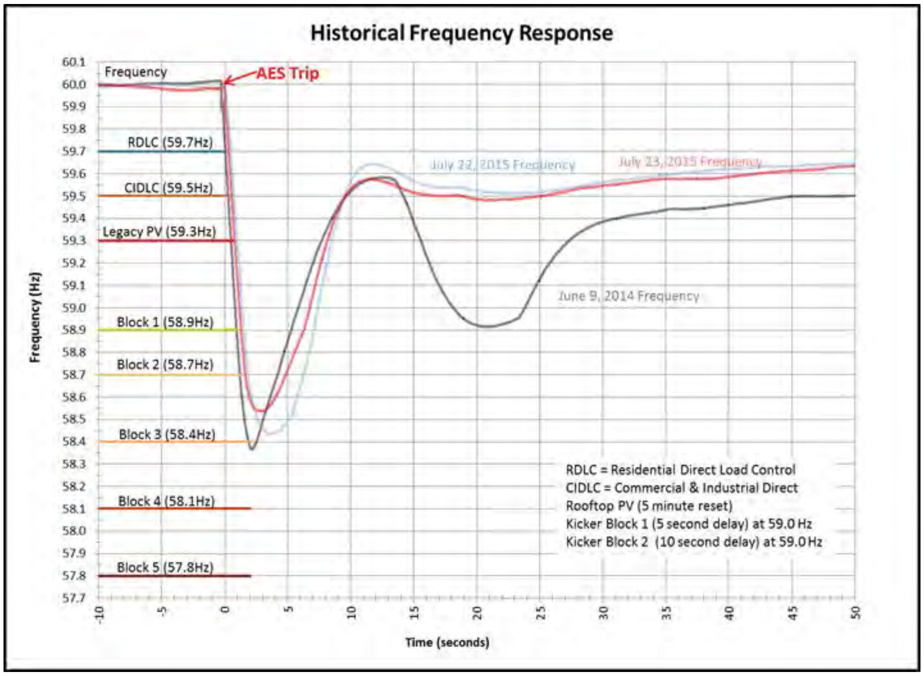

Figure O-8. Frequency Response Profile of Historic Contingency Events

Table O-6 shows the system characteristics of the historical system events.

	June 9, 2014 Event 9:49 AM	July 22, 2015 Event 11:23 AM	July 23, 2015 Event 11:22 AM
System Load	880 MW	920 MW	890 MW
Generator Units On-Line	K1, K2, K3, K4, K5, K6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP
Total Kinetic Energy	6233	6059	6059
Synchronous Inertia Response	211	169	197
AES Gross MW Loss of Generation	198 MW	198 MW	180 MW
Excess Spinning Reserve	130 MW	103 MW	117 MW
Excess Quick Load Pick Up	50 MW	72 MW	78 MW
Estimated PV Tripped at 59.3Hz	50 MW	56 MW	55 MW
Frequency Nadir	58.4 Hz	58.4 Hz	58.5 Hz
Rate of Change of Frequency*	-0.94	-0.75	-0.84
Number of UFLS Blocks Shed	Blocks 1-3 (96 MW) & Block 5 (13.5 MW)**	Kicker Block 1 (20 MW) & Blocks 1-2 (62 MW)	Kicker Block 1 (20 MW) & Blocks 1-2 (65 MW)
*Note: Circuit in Block 5 tripped causing additional load shed			

Table O-6. Historical Contingency Events

2017

Loss of Generation Simulation

System security analysis was performed on two hours that were selected from the Theme 5 (a no-LNG case with generation modernization) production simulation data that represents a typical hour and a boundary condition.

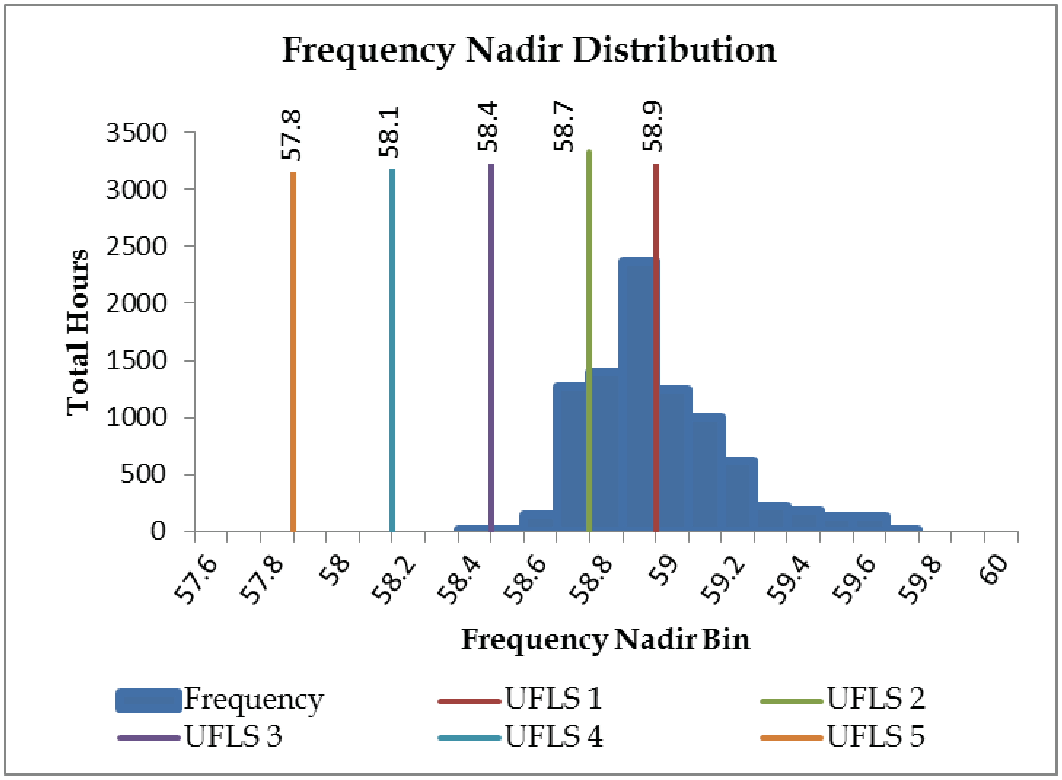

Figure O-9. Frequency Nadir Histogram 2017

Figure O-9 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2017. The typical hour selected from the maximum distribution of 1275 hours was 1:00 PM on Friday, November 24. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 9 hours was 4:00 AM on Sunday, March 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

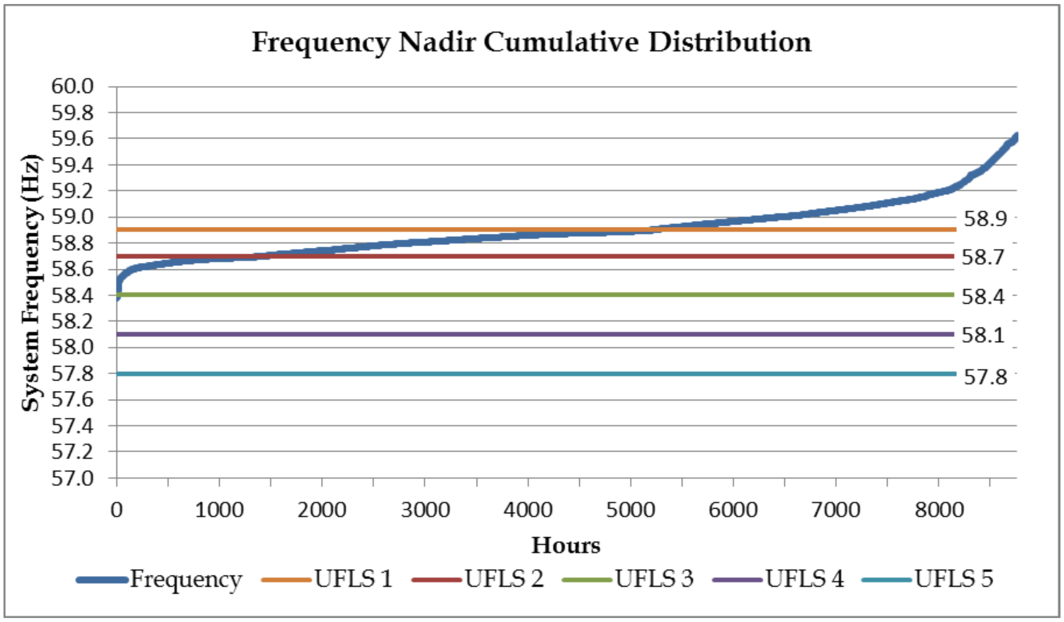

Figure O-10. Frequency Nadir Distribution Curve 2017

Figure O-10 shows the frequency nadir duration curve for the Theme 5 resource plan in 2017. The system is at risk of UFLS for 5203 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Fri 11/24/17 Hour 13			Theme 5 - AES Trip Boundary Sun 3/26/17 Hour 4		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	16.0	6.5	6.0			
AES	189.0	63.0			2.57	239.0	615	180.0	9.0	117.0	180.0	9.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.0	24.0	31.0	74.0	10.0	45.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	21.0	19.0	11.0	16.0	24.0	6.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.0	24.0	31.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	5.0	VPO	VPO	26.0	56.2	2.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426				26.0	56.2	2.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	6.0	VPO	VPO	37.0	49.2	13.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	6.0	VPO	VPO	26.0	59.3	2.4
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692	40.0	93.8	0.0			
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261	23.5	31.0	0.0			
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO	24.0	59.3	0.2
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124						
Honolulu 9	0.0	0.0			1.95	64.0	125						
Total Wind	99	0						21			5		
-Kahuku	30	0						5			0		
-Kawailoa	69	0						16			5		
-Na Pua Makani													
-CBRE Wind													
DG-PV	590	0						350			0		
Station PV	39	0						24			0		
Total Kinetic Energy									6074			4386	
Total Load									892			584	
Total Thermal Generation									497			579	
Total Renewable Generation									395			5	
Total Generation									892			584	
Excess Generation									0			0	
Total Up Regulation									321			334	
Total Down Regulation									217			312	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		43.6	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		128.1	60.5Hz Output		0.0

Table O-7. Unit Commitment and Dispatch 2017

Table O-7 shows the unit commitment and dispatch schedules for the typical hour (11/24/17, 1:00 PM) and boundary hour (3/26/17, 4:00 AM).

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For O'ahu, this is an AES turbine trip at full output and the subsequent loss of generation from legacy PV.

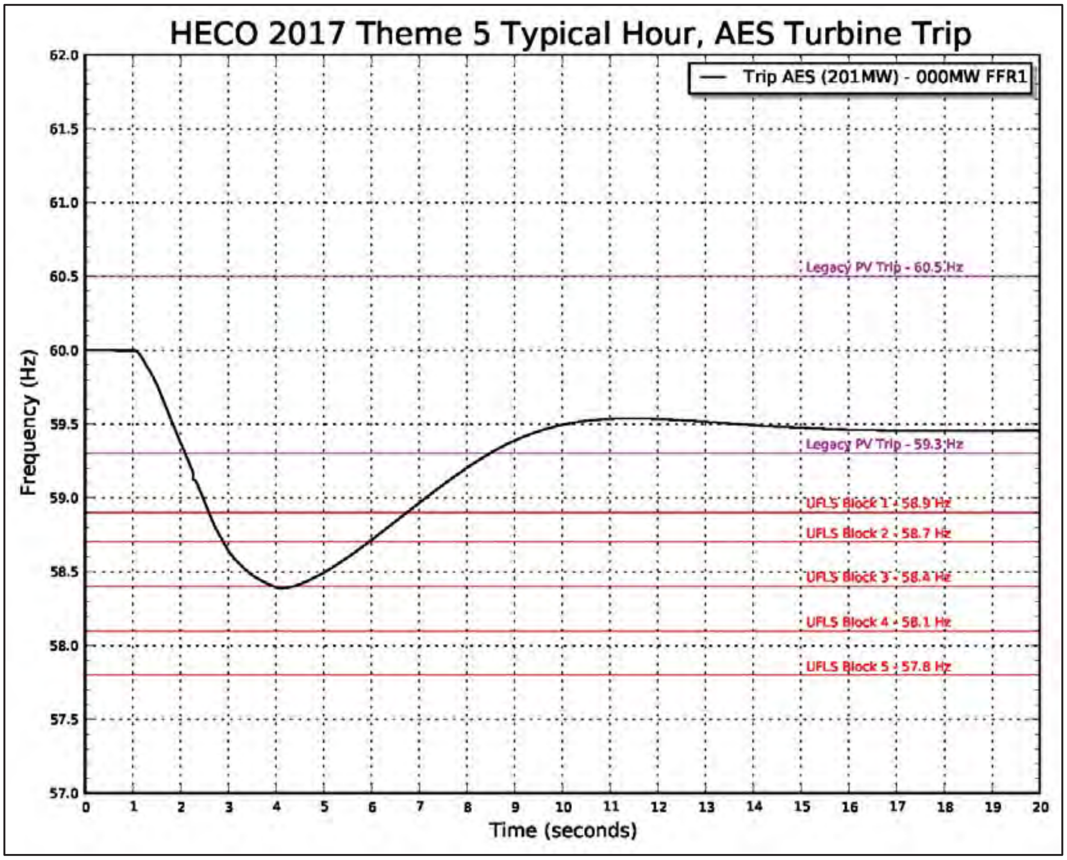

Figure O-11. Frequency Response Profile Typical Hour

Figure O-11 shows the frequency response profile for an AES trip for a typical hour. System kinetic energy is 6074 MW-sec and the capacity of legacy PV that will disconnect from the system is 43.6 MW. The frequency nadir breached 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

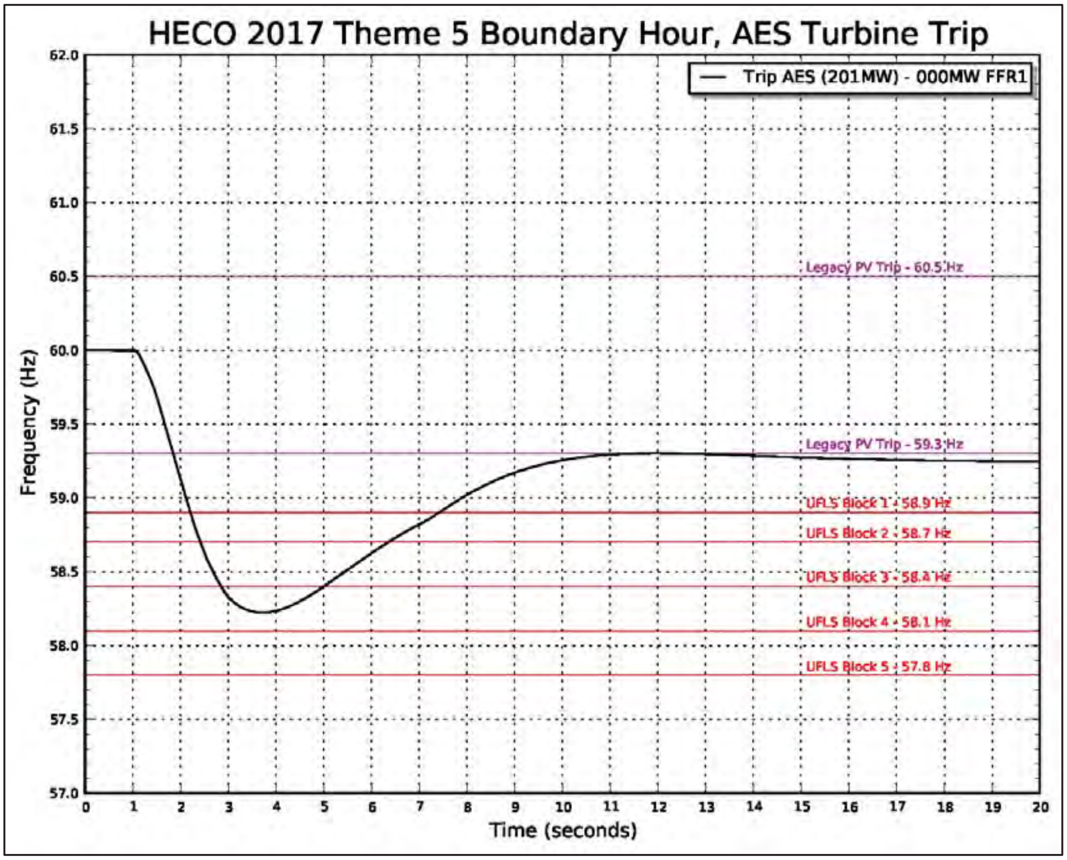

Figure O-12. Frequency Response Profile Boundary Hour

Figure O-12 shows the frequency response profile for the boundary hour. System kinetic energy is 4386 MW-sec. The frequency nadir breached 58.3 Hz that requires three blocks of UFLS to stabilize system frequency.

138 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

In addition, the aggregate loss of inverter-based generation could drive the system frequency nadir below critical operating thresholds. The under frequency trips settings for thermal units typically activate at 57.0 Hz with various time delay setting depending on turbine manufacturer recommendations. At 56.0 Hz, synchronous generators will trip and inverter-based generation will disconnect from the system.

For the fault analysis, a three-phase fault was placed on transmission elements to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles with breaker reclosing activated after a 30-cycle time delay. Delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. A breaker failure initiates the backup protection scheme that opens adjacent circuit breakers to clear the fault, isolating an additional 138 kV circuit.

Table O-8 shows the unit commitment and dispatch for the fault analysis.

Unit	Unit Ratings							Theme 5 - Fault Sun 7/23/17 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.1	12.4	0.1
AES	189.0	63.0			2.57	239.0	615	117.9	71.1	54.9
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	46.7	37.3	17.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	22.2	17.8	12.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	46.7	37.3	17.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	5.0	VPO	VPO
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	5.7	VPO	VPO
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	7.4	VPO	VPO
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	5.4	VPO	VPO
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692	40.0	93.8	0.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256	23.8	29.9	0.0
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	8.0	VPO	VPO
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447	5.9	44.0	0.0
CIP1	112.2	41.2			4.72	162.0	765			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	109	0						21		
-Kahuku	30	0						6		
-Kawailoa	69	0						15		
-Na Pua Makani	24	0						0		
-CBRE Wind	10	0						0		
DG-PV	590	0						472		
Station PV	78	0						34		
Total Kinetic Energy								6251		
Total Load								924		
Total Thermal Generation								397		
Total Renewable Generation								527		
Total Generation								924		
Excess Generation								0		
Total Up Regulation								344		
Total Down Regulation								124		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-8. Unit Commitment and Dispatch Fault Analysis

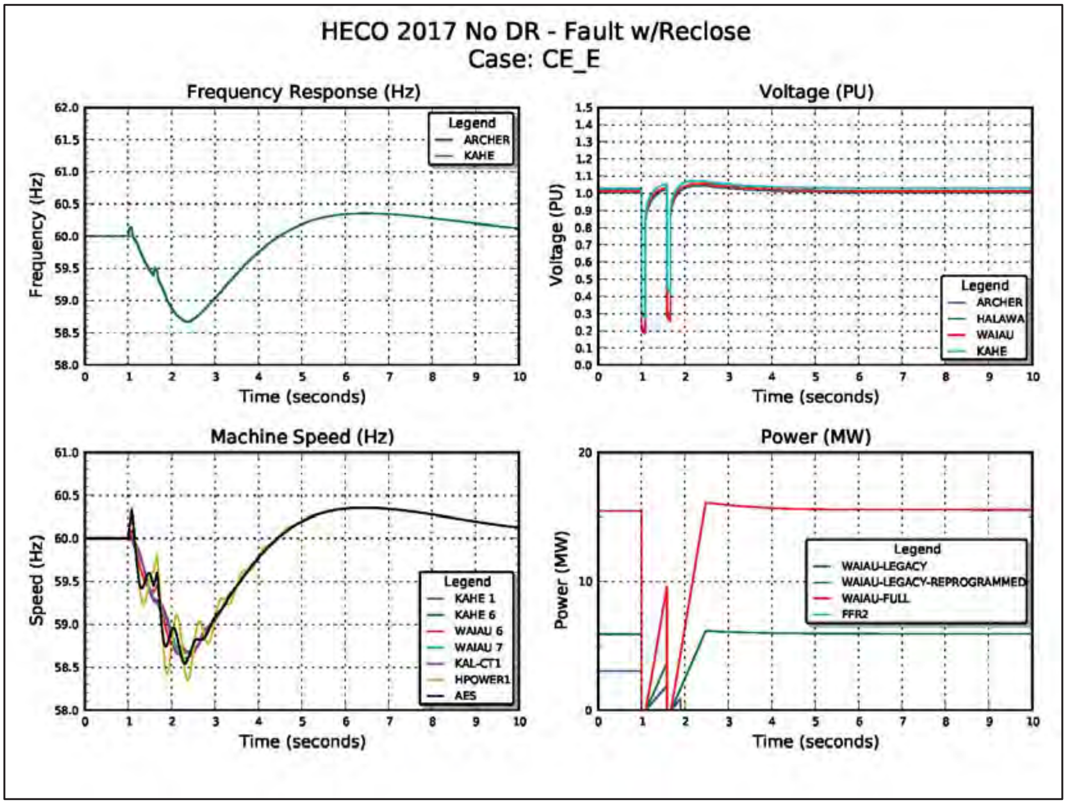

Figure O-13. System Performance for Normally Cleared Fault

Figure O-13 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 472 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from DG-PV is restored but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and two blocks of UFLS are able to stabilize system frequency at 58.7 Hz. The system remains stable for all normally cleared faults.

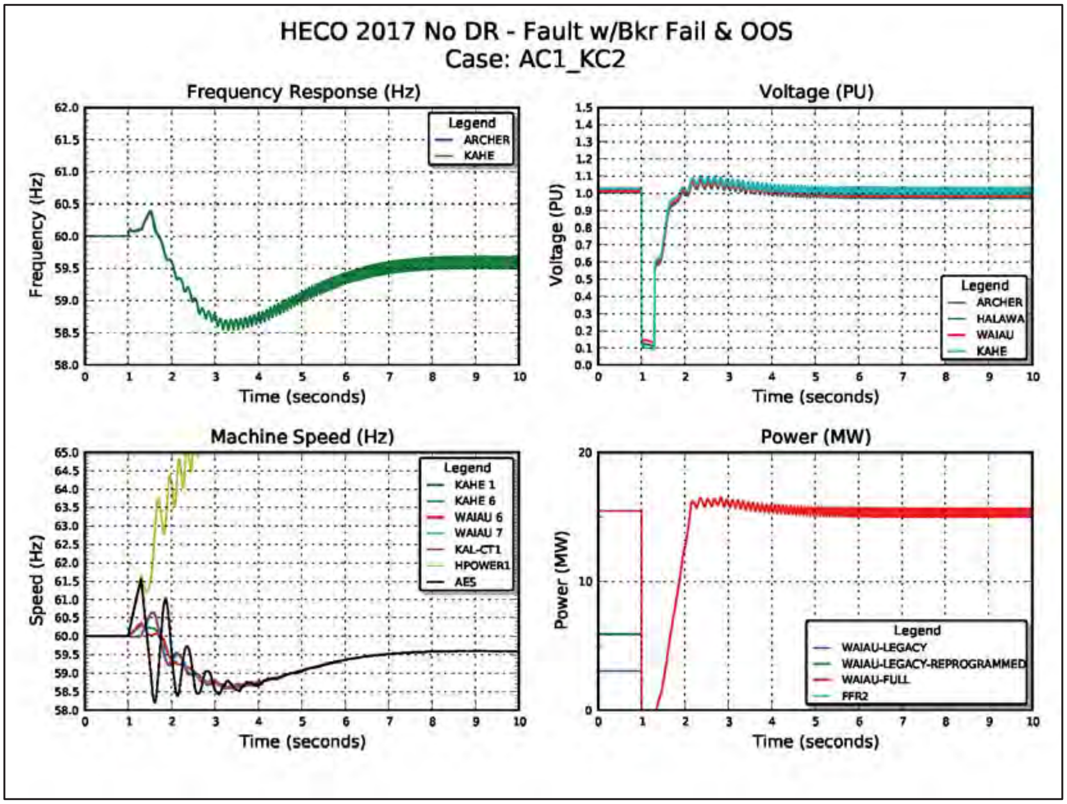

Figure O-14. System Performance for Delay Cleared Fault

Figure O-18 shows the system performance for a delay cleared fault on the AES-CEIP 1 circuit and BKR 323 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the Kahe-CEIP2 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 472 MW of inverter-based generation to trip offline. HPOWER 1 loses synchronism almost immediately after the fault, indicating the delayed clearing exceeded its critical clearing time for stability. Further analysis is required to determine if HPOWER 1 requires out-of-step protection.

2017 138 kV Fault Analysis					
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Stable
AES-HP	AES	320	15	AES-CEIP 1	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable

Table O-9. Summary of Results Breaker Fail Analysis

Table O-9 is the summary of results for the breaker failure analysis. Seven simulations resulted in system instability where HPOWER 1 lost synchronism and/or system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip.

Post April No DR Plan - Theme 5

System security analysis performed on the Theme 5 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 5 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The O‘ahu transmission system is designed to operate with two transmission lines out of service (N-2) while maintaining a minimum bus voltage of 0.92 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum 515 MVA requirement. Therefore, only synchronous condensers are evaluated in these analyses.

For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 8/5/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	34.0	6.0	24.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	27.0	59.2	3.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692	29.9	104.7	8.9
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124		Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125		Synch. Cond.	
Total Wind	133.0	0.0						70.0		
-Kahuku	30.0	0.0						17.0		
-Kawailoa	69.0	0.0						27.0		
-Na Pua Makani	24.0	0.0						21.0		
-CBRE Wind	10.0	0.0						5.0		
-Future Wind	0.0	0.0								
-Offshore Wind	0.0	0.0								
Total Station PV	182.2	0.0						165.0		
-KS2	5.0	0.0						5.0		
-KREP	5.0	0.0						4.0		
-Waianae	27.6	0.0						27.6		
-Kawailoa PV	49.0	0.0						33.8		
-Mililani 2	14.7	0.0						14.7		
-Waiawa	45.9	0.0						45.9		
-Westloch	20.0	0.0						20.0		
-CBRE PV	15.0	0.0						14.0		
DG-PV	701.0	0.0						469.0		
Total Kinetic Energy								4269		
Total Load								1262		
Total Thermal Generation								558		
Total Renewable Generation								704		
Total Generation								1262		
Excess Generation								0		
Total Up Regulation								296		
Total Down Regulation								300		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		49.2
	60.5Hz Capacity			215.9				60.5Hz Output		144.4

Table O-10. Unit Commitment and Dispatch 2019 QV Analysis

Table O-10 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 8/5/19 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	34.1	65.3	-83.9
Kalaeloa CT-1	84.5	-35.9	17.9	66.6	-53.8
Kalaeloa ST	84.5	-35.8	17.9	66.6	-53.7
Kalaeloa CT-2	42.1	-16.7	17.9	24.2	-34.6
Kahe 1	71.0	-52.0			
Kahe 2	68.3	-51.6	43.7	24.7	-95.2
Kahe 3	73.7	-24.3	43.7	30.0	-68.0
Kahe 4	67.7	-24.1	43.7	24.0	-67.7
Kahe 5	117.8	-71.3	100.9	16.9	-172.2
Kahe 6	111.8	-64.2			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	87.4	-110.9	19.3	68.1	-130.2
-Kahuku	17.9	-17.9	6.6	11.2	-24.5
-Kawailoa	50.0	-74.5	9.0	41.0	-83.5
-Na Pua Makani	16.4	-15.4	3.6	12.8	-19.0
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	14.2	95.2	-123.6
-KS2	1.6	-1.6	1.6	0.0	-3.3
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	3.2	11.3	-17.7
-Kawailoa PV	36.8	-36.8	-0.4	37.2	-36.3
-Mililani 2	10.7	-10.7	0.4	10.3	-11.1
-Waiawa	32.9	-32.9	3.8	29.1	-36.7
-Westloch	6.3	-6.3	3.5	2.8	-9.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.8
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			325.3		
Total Renewable MVAR Generation			33.4		
Total Cap Bank MVAR			183.5		
Charging MVAR			76.4		
Total MVAR Supply			618.5		
Total MVAR Load			411.0		
Total MVAR Losses			207.6		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				540.0	
Total MVAR Absorb Capability					-904.6

Table O-11. MVAR Capability 2019 QV Analysis

Table O-11 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School

Table O-12. N-2 Contingencies 2019 QV Analysis

Table O-12 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

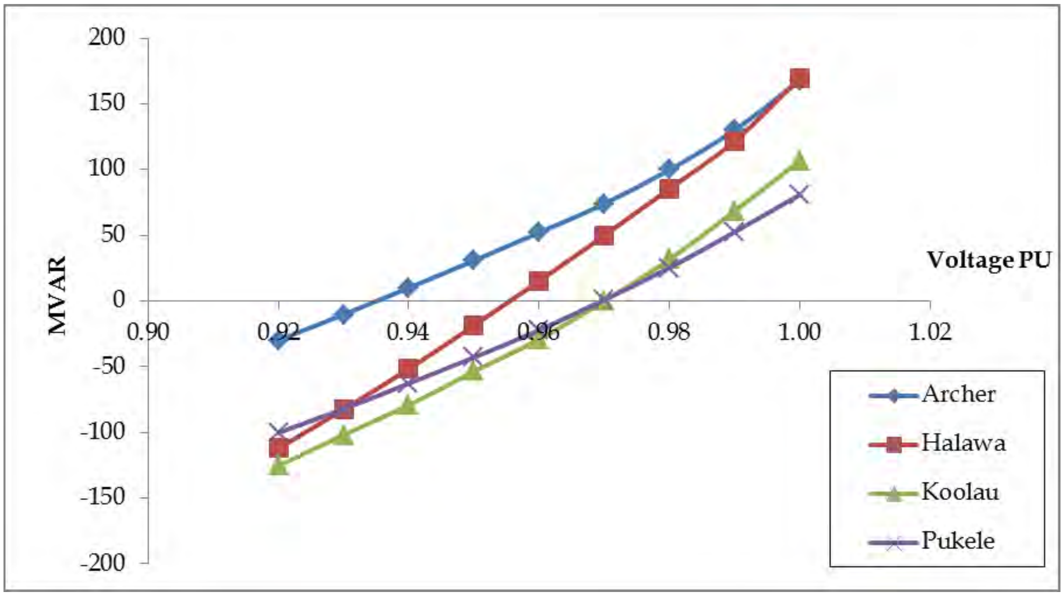

Figure O-15. QV Curves 2019

Figure O-15 shows the QV curves for the Archer, Halawa, Ko‘olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation requires an additional 31 MVAR to maintain system voltage at 0.95 PU for an N-2 contingency. The system has 540 MVAR of reactive power reserve capacity but all of these resources are on the west side of the island, far from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	168	154	130	154	100	135	74	135	52	135	31	135	10	135	-10	135	-30
120	Halawa	125	170	154	122	154	86	154	50	154	15	154	-19	154	-52	154	-82	154	-112
150	Koolau	154	107	154	69	154	32	125	0	125	-29	125	-54	125	-79	125	-102	125	-125
170	Pukele	154	81	154	53	125	25	125	1	125	-22	125	-43	125	-63	125	-82	125	-100

Table O-13. Summary of Results 2019 QV Analysis

Table O-13 shows the summary of results for the 2019 QV analysis. The Archer bus requires 31 MVAR to maintain 0.95 PU voltage for outages of the Halawa-Iwilei and Halawa-School circuits.

To mitigate the reactive power shortfall at Archer Substation, analysis was performed with Honolulu 8 and 9 synchronous condensers added to the system.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 8/5/19 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	29.3	70.1	-79.1
Kalaeloa CT-1	84.5	-35.9	15.6	68.9	-51.5
Kalaeloa ST	84.5	-35.8	15.6	68.9	-51.4
Kalaeloa CT-2	42.1	-16.7	15.6	26.5	-32.3
Kahe 1	71.0	-52.0			
Kahe 2	68.3	-51.6	31.8	36.5	-83.4
Kahe 3	73.7	-24.3	31.8	41.8	-56.2
Kahe 4	67.7	-24.1	31.8	35.8	-55.9
Kahe 5	117.8	-71.3	100.9	17.0	-172.2
Kahe 6	111.8	-64.2			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	21.1	29.9	-54.1
Hon 9 (Sync Cond)	51.0	-33.0	21.1	29.9	-54.1
Total Wind	87.4	-110.9	16.3	71.1	-127.2
-Kahuku	17.9	-17.9	6.3	11.6	-24.1
-Kawailoa	50.0	-74.5	7.9	42.1	-82.4
-Na Pua Makani	16.4	-15.4	2.1	14.3	-17.5
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	13.5	95.9	-123.0
-KS2	1.6	-1.6	1.6	0.0	-3.3
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	3.2	11.3	-17.7
-Kawailoa PV	36.8	-36.8	-0.4	37.2	-36.3
-Mililani 2	10.7	-10.7	0.3	10.4	-11.0
-Waiawa	32.9	-32.9	3.3	29.6	-36.2
-Westloch	6.3	-6.3	3.5	2.8	-9.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.8
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			320.2		
Total Renewable MVAR Generation			29.8		
Total Cap Bank MVAR			183.6		
Charging MVAR			77.2		
Total MVAR Supply			610.8		
Total MVAR Load			411.0		
Total MVAR Losses			199.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				650.8	
Total MVAR Absorb Capability					-928.9

Table O-14. MVAR Capability QV Sensitivity Analysis

Table O-14 shows the MVAR capability from the generating resources from the unit commitment and dispatch with the addition of Honolulu 8 and 9 synchronous condensers, increasing the system's reactive power capacity by 60 MVAR.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1

Table O-15. N-2 Contingencies QV Sensitivity

Table O-15 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

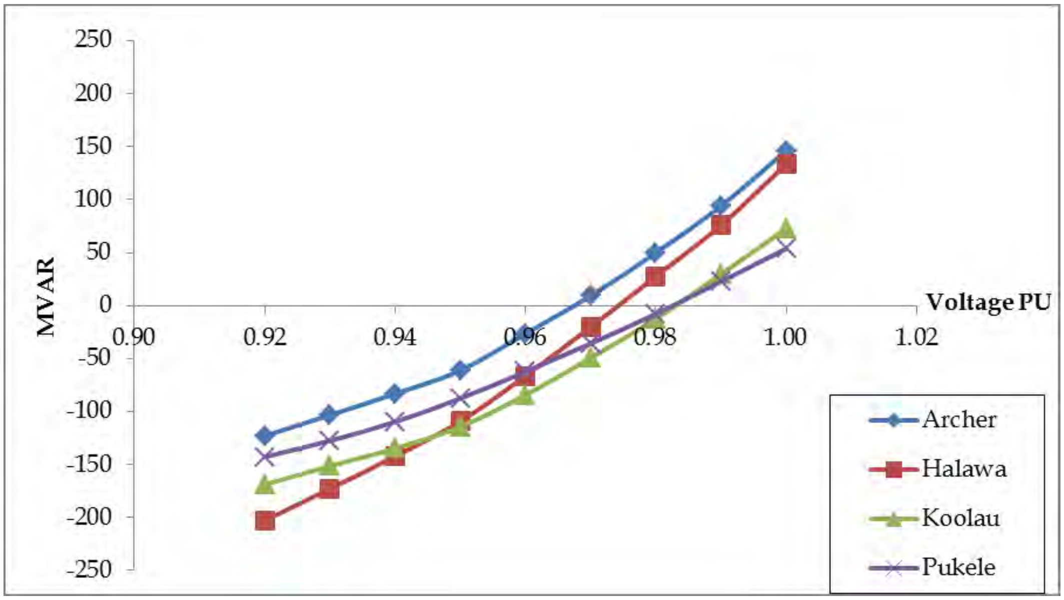

Figure O-16. QV Curves with H8 & H9 Synchronous Condensers

Figure O-16 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation is able to maintain bus voltage at 0.95 PU with the additional 60 MVAR of reactive power from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	146	154	94	154	50	135	9	135	-26	135	-61	135	-83	135	-103	135	-123
120	Halawa	125	134	154	76	154	28	154	-20	154	-66	154	-109	154	-142	154	-173	154	-203
150	Koolau	125	73	125	30	125	-12	125	-49	125	-84	125	-114	203	-135	203	-151	203	-169
170	Pukele	125	54	125	23	125	-8	125	-36	125	-62	125	-88	125	-110	203	-128	203	-143

Table O-16. QV Analysis Summary of Results H8 & H9 Synchronous Condensers

Table O-16 shows the results of the QV analysis with the Honolulu 8 and 9 synchronous condensers. The unit commitment and dispatch in conjunction with the Honolulu 8 and 9 synchronous condensers are able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Analysis was performed on two hours from the Theme 5 production simulation data that represent a typical and a boundary condition.

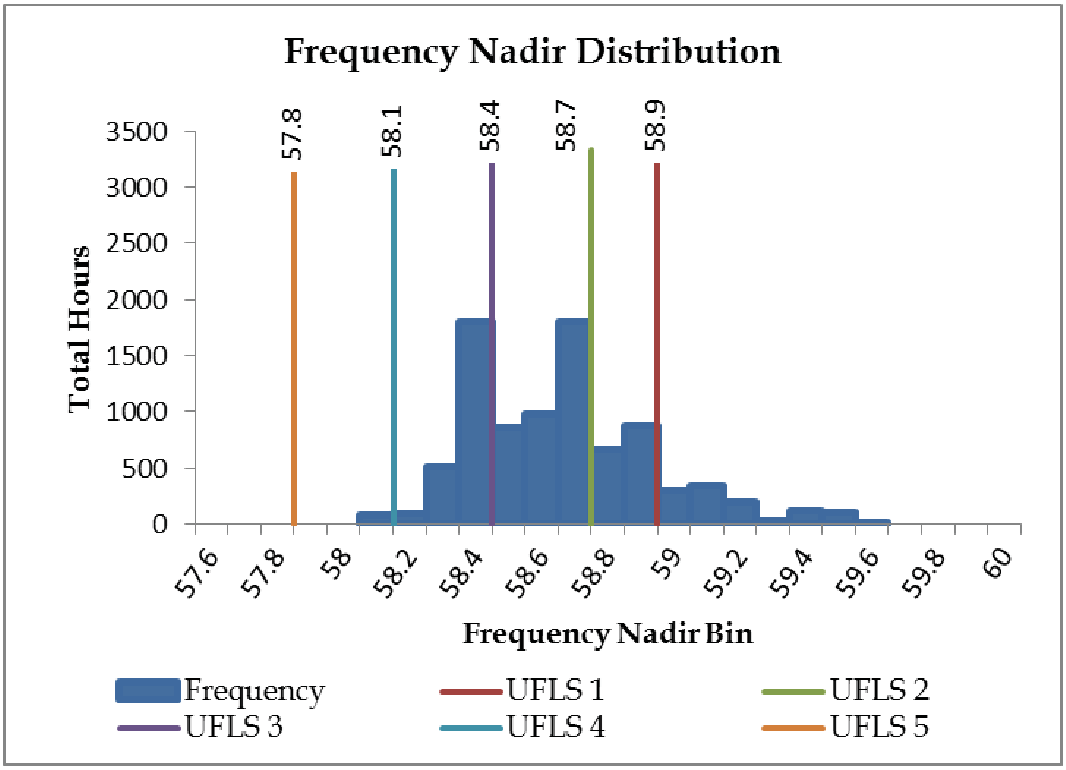

Figure O-17. Frequency Nadir Histogram for 2019

Figure O-17 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production simulation data. The typical hour was selected from the maximum distribution of 1797 hours was 12:00 PM on Monday, June 10. The frequency nadir range for the typical hour is 58.3 - 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 60 hours was 11:00 AM on Monday, May 27. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

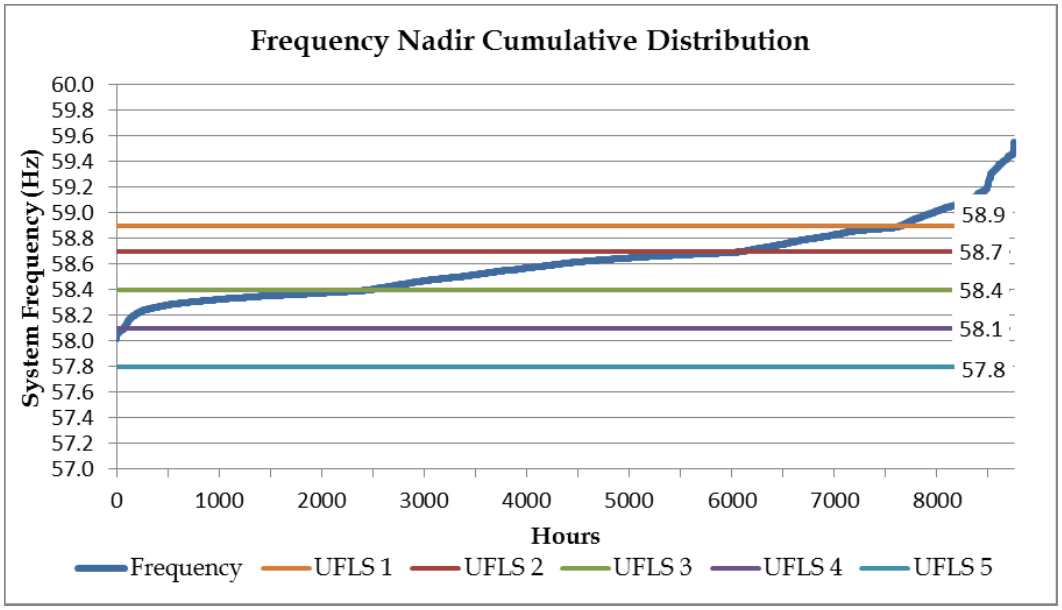

Figure O-18. Frequency Nadir Duration Curve 2019

Figure O-18 shows the frequency nadir duration curve for the Theme 5 resource plan in 2019. The system is at risk of UFLS for 7661 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Mon 10/14/19 Hour 11			Theme 5 - AES Trip Boundary Fri 11/29/19 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.2	11.8	43.2	48.7	35.3	19.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	34.4	5.6	24.4	23.2	16.8	13.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	72.2	11.8	43.2	48.7	35.3	19.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	22.9	111.7	1.9	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.0	58.3	1.2			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						32			38		
-Kahuku	30	0						4			4		
-Kawailoa	69	0						9			17		
-Na Pua Makani	24	0						18			14		
-CBRE Wind	10	0						1			3		
DG-PV	701	0						396			383		
Station PV	183	0						136			121		
Total Kinetic Energy								4518			3735		
Total Load								1074			961		
Total Thermal Generation								511			419		
Total Renewable Generation								564			541		
Total Generation								1074			960		
Excess Generation								0			0		
Total Up Regulation								344			267		
Total Down Regulation								253			209		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		41.5	59.3Hz Output		40.2
	60.5Hz Capacity			215.9				60.5Hz Output		121.9	60.5Hz Output		118.0

Table O-17. Commitment and Dispatch 2019

Table O-17 shows the unit commitment and dispatch for the typical hour (10/14/19, 11:00 AM) and boundary hour (11/29/19, 12:00 PM).

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

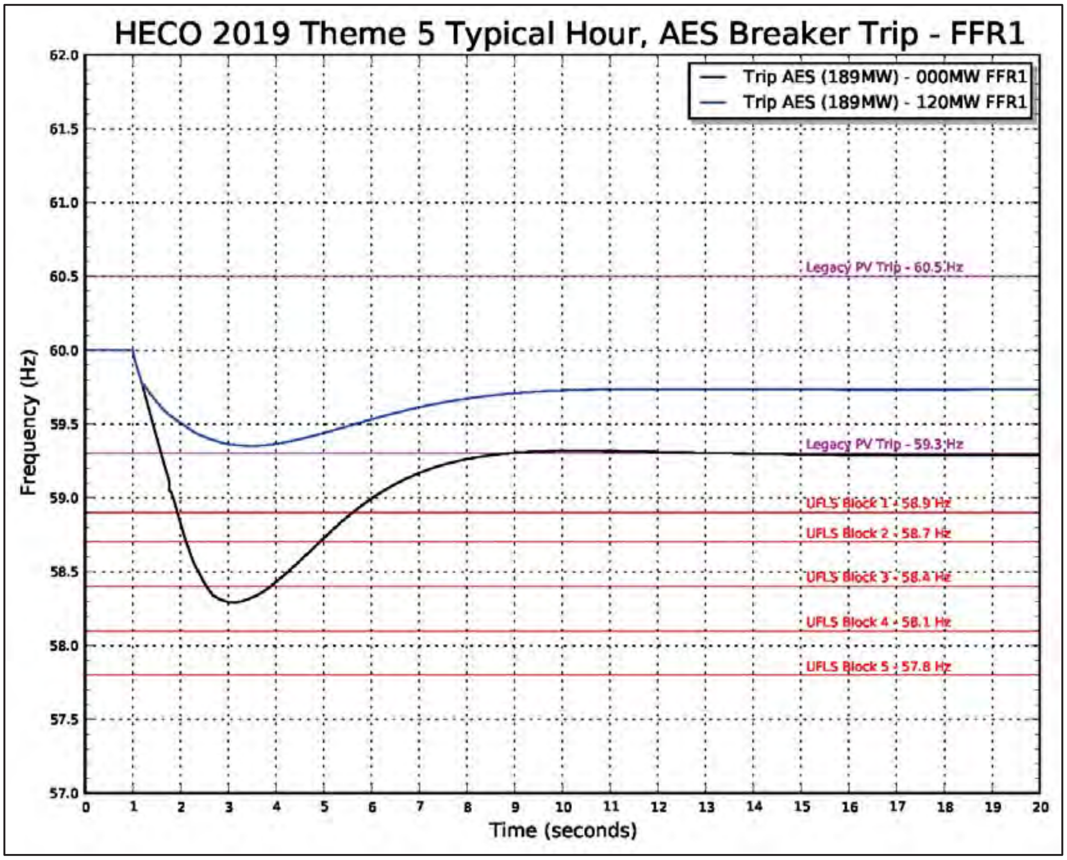

Figure O-19. Frequency Response Profile for FFR1 Typical Hour

Figure O-19 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4518 MW-sec and the capacity of legacy PV that will disconnect from the system is 41.5 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

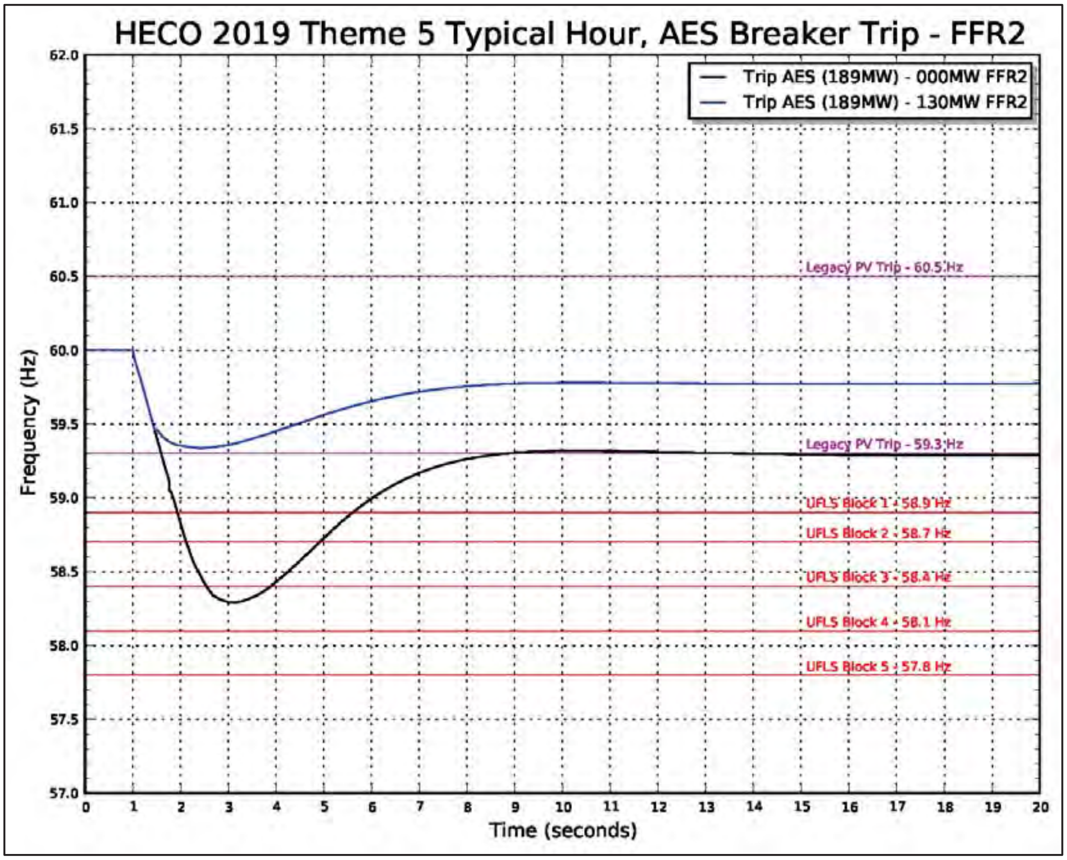

Figure O-20. Frequency Response Profile for FFR2 Typical Hour

Figure O-20 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

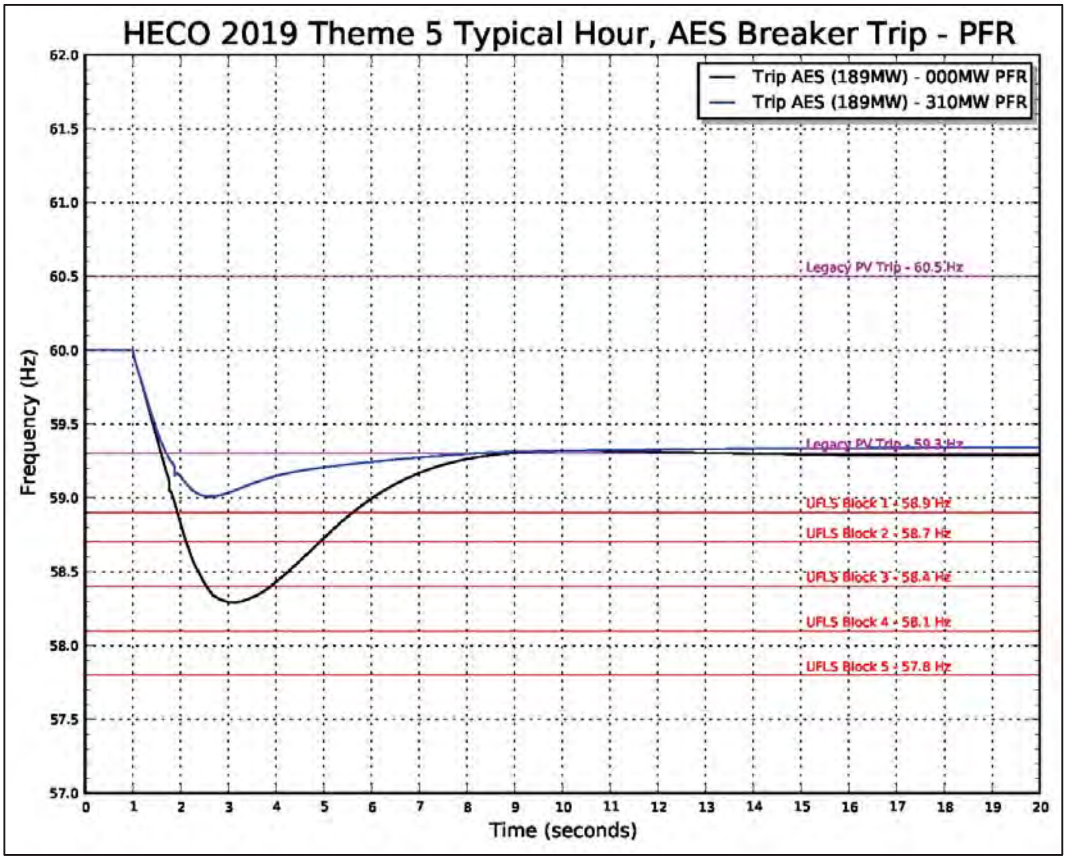

Figure O-21. Frequency Response Profile for PFR Typical Hour

Figure O-21 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 310 MW. This is in addition to the 368 MW of upward regulation from thermal generation.

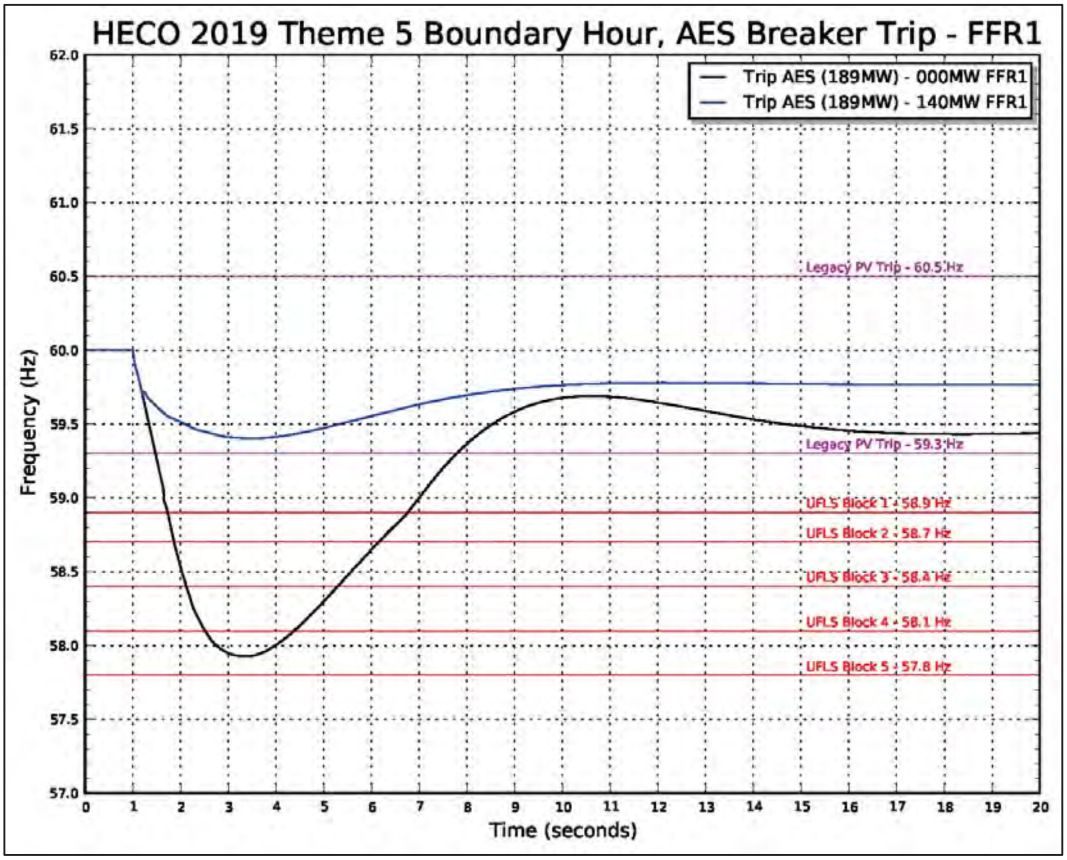

Figure O-22. Frequency Response Profile for FFR1 Boundary Hour

Figure O-22 shows the frequency response profile for an AES trip at 179 MW for a boundary hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.2 MW. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

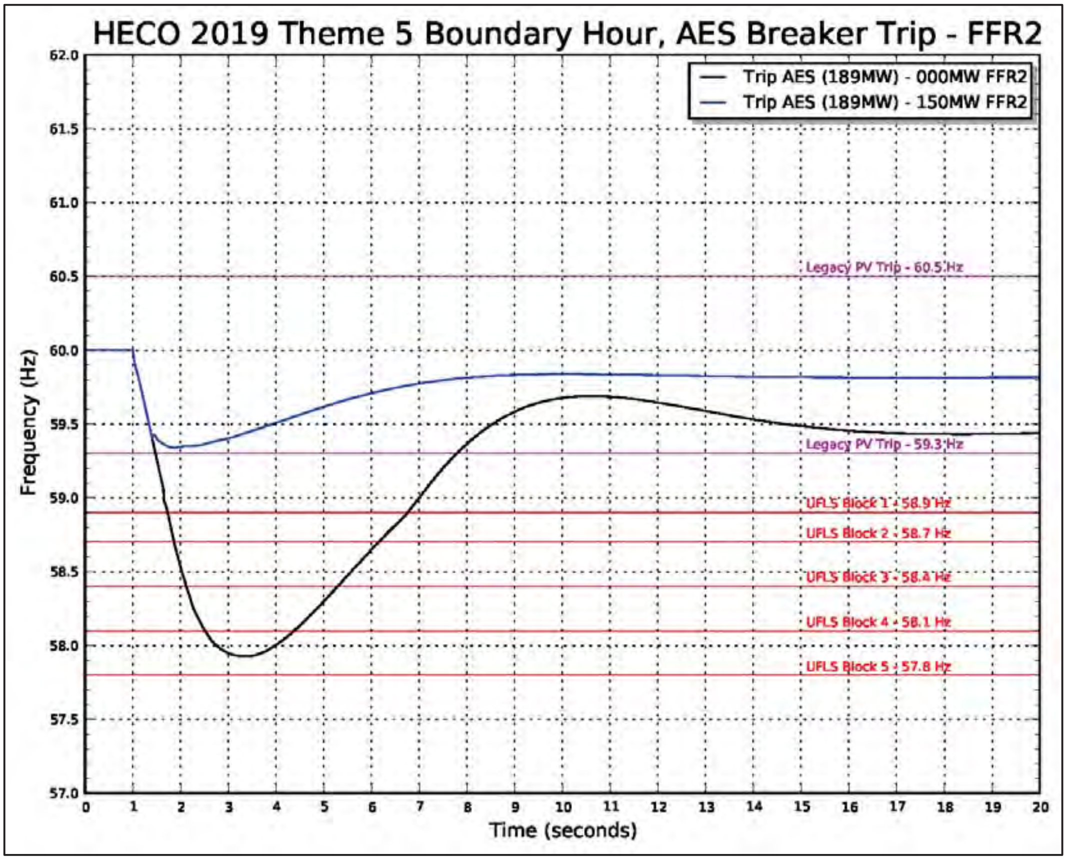

Figure O-23. Frequency Response Profile for FFR2 Boundary Hour

Figure O-23 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

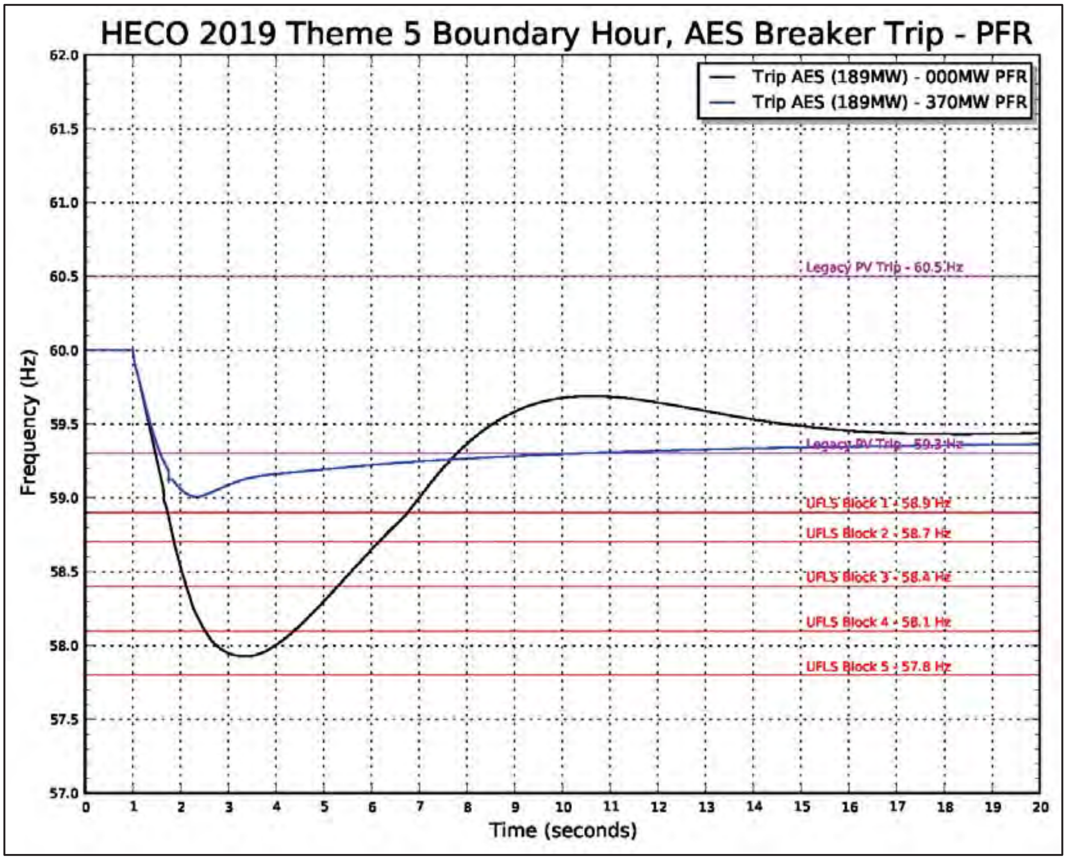

Figure O-24. Frequency Response Profile PFR Boundary Hour

Figure O-24 shows the frequency response profile for the PFR analysis. The capacity of PFR to meet TPL-001 is 370 MW. This is in addition to the 226 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Wed 6/12/19 Hour 11			Theme 5 - K5 Trip Boundary Fri 11/29/19 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	98.0	91.0	35.0	75.0	114.0	12.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	83.8	0.2	54.8	48.7	35.3	19.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.9	0.1	29.9	23.2	16.8	13.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	83.8	0.2	54.8	48.7	35.3	19.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	42.2	44.0	18.5	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						31			38		
-Kahuku	30	0						3			4		
-Kawailoa	69	0						11			17		
-Na Pua Makani	24	0						15			14		
-CBRE Wind	10	0						2			3		
DG-PV	701	0						261			383		
Station PV	183	0						111			121		
Total Kinetic Energy								4092			3735		
Total Load								975			961		
Total Thermal Generation								571			419		
Total Renewable Generation								404			541		
Total Generation								975			960		
Excess Generation								0			0		
Total Up Regulation								200			267		
Total Down Regulation								337			208		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		27.4	59.3Hz Output		40.2
	60.5Hz Capacity			215.9				60.5Hz Output		80.5	60.5Hz Output		118.0

Table O-18. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-18 shows the unit commitment and dispatch for the typical hour (6/12/19, 11:00 AM) and boundary hour (11/29/19, 12:00 PM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

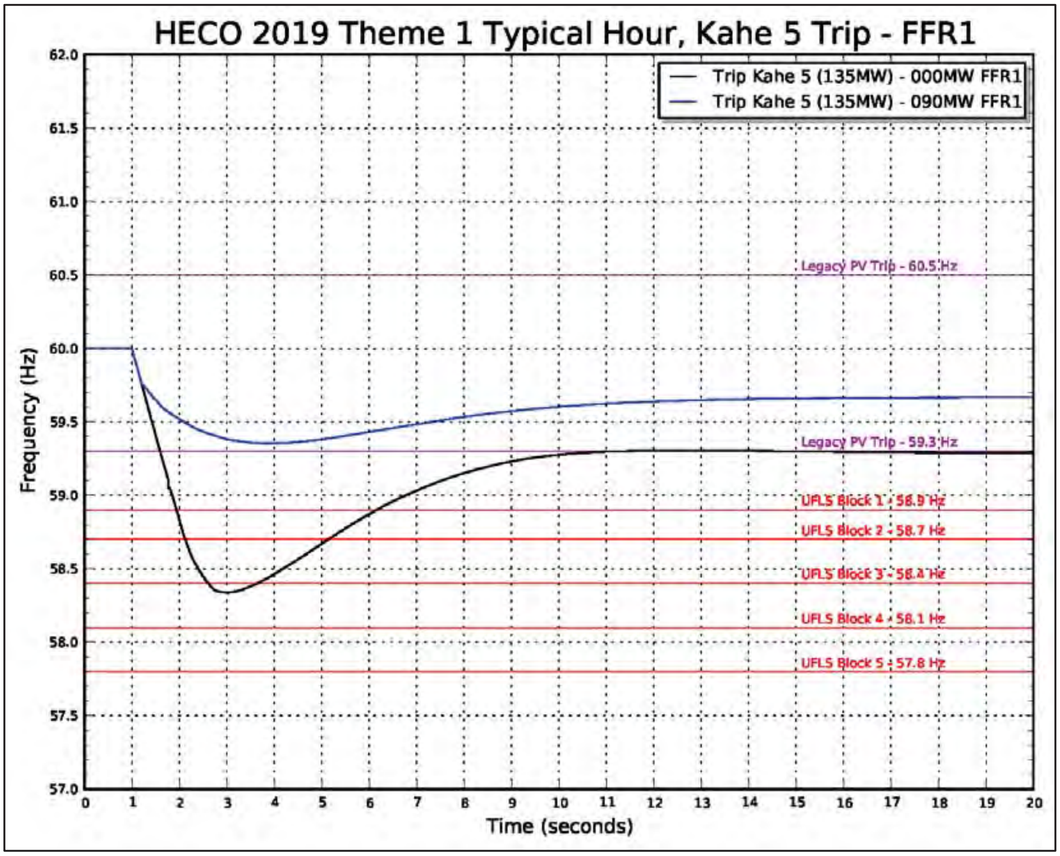

Figure O-25. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-25 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4092 MW-sec and the capacity of legacy PV that will disconnect from the system is 27.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW.

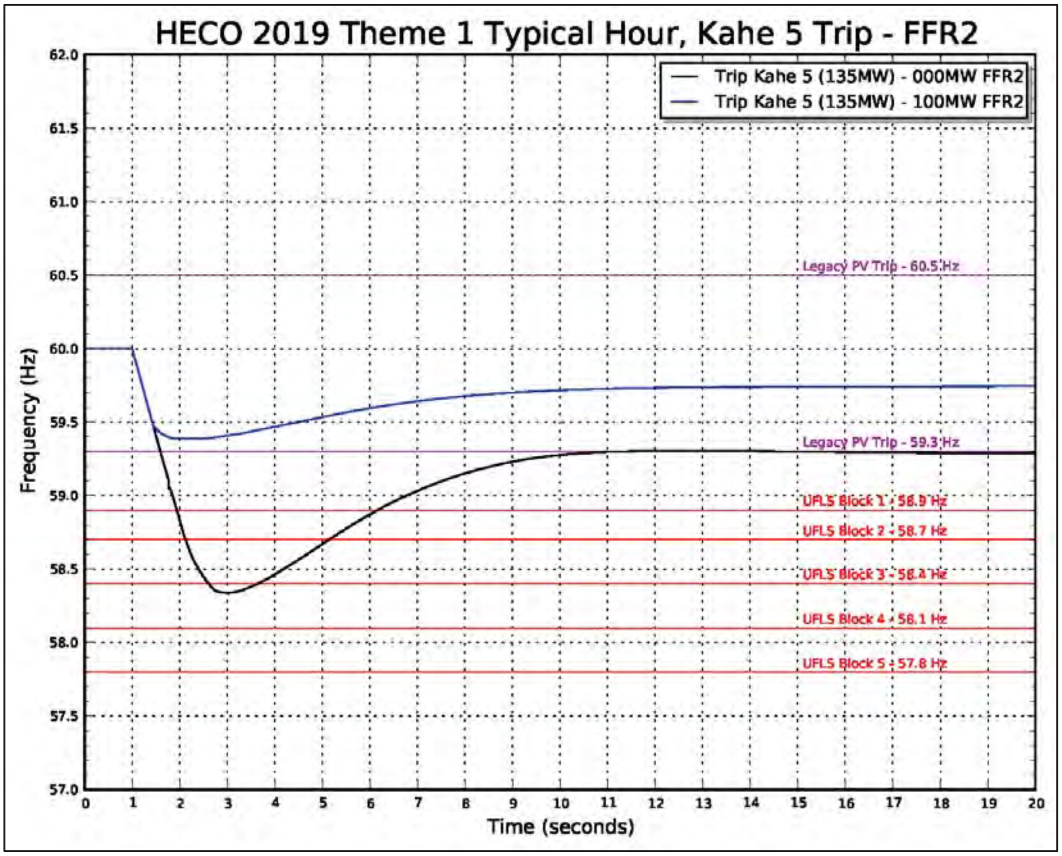

Figure O-26. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-26 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

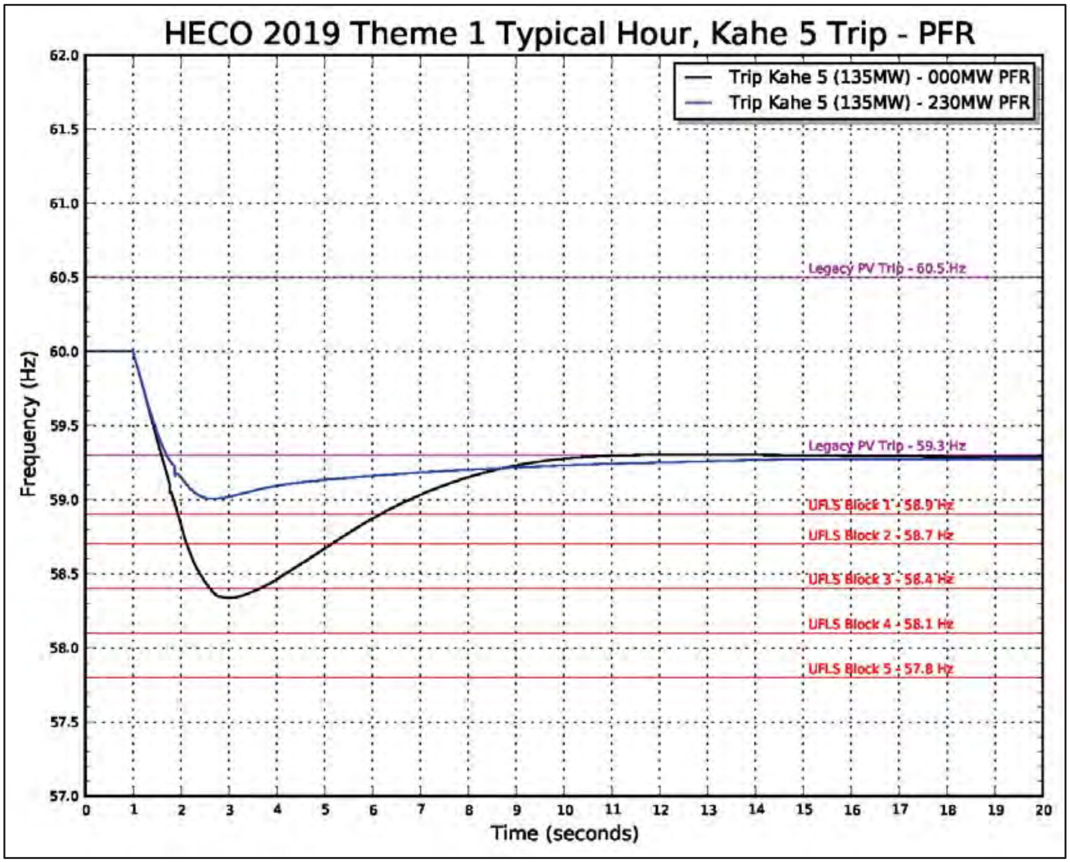

Figure O-27. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-27 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 216 MW of upward regulation from thermal generation.

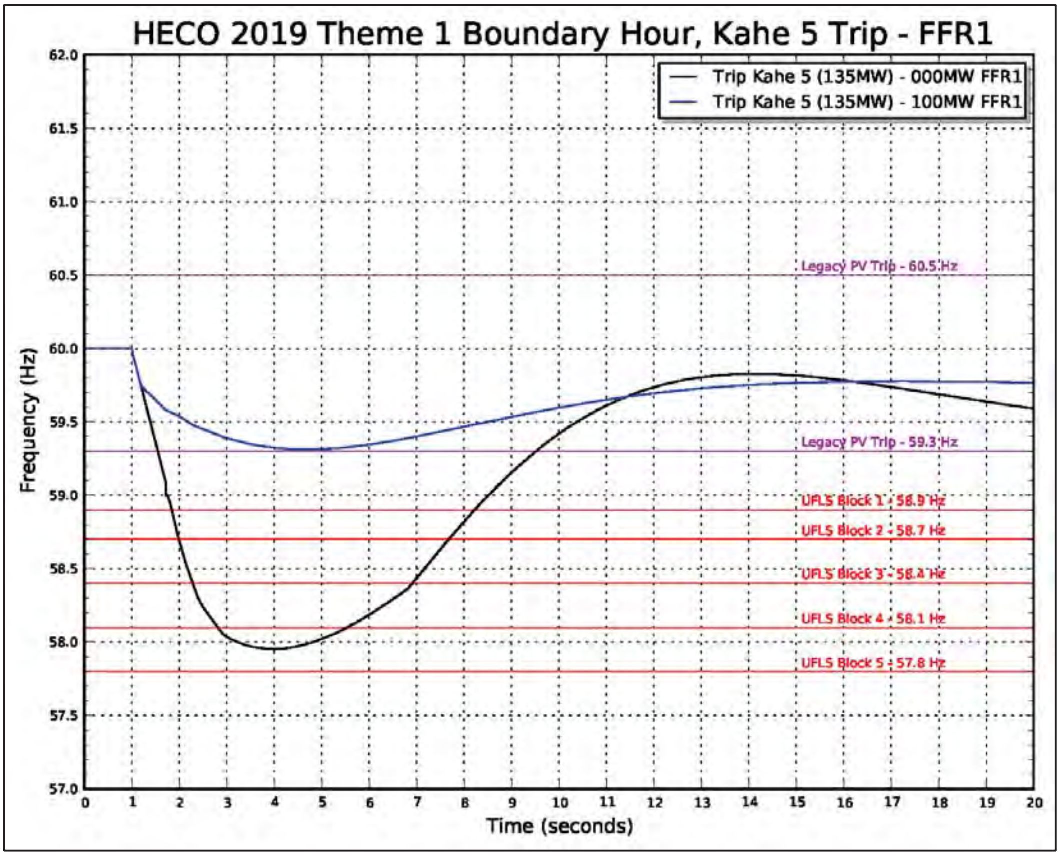

Figure O-28. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-28 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.2 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

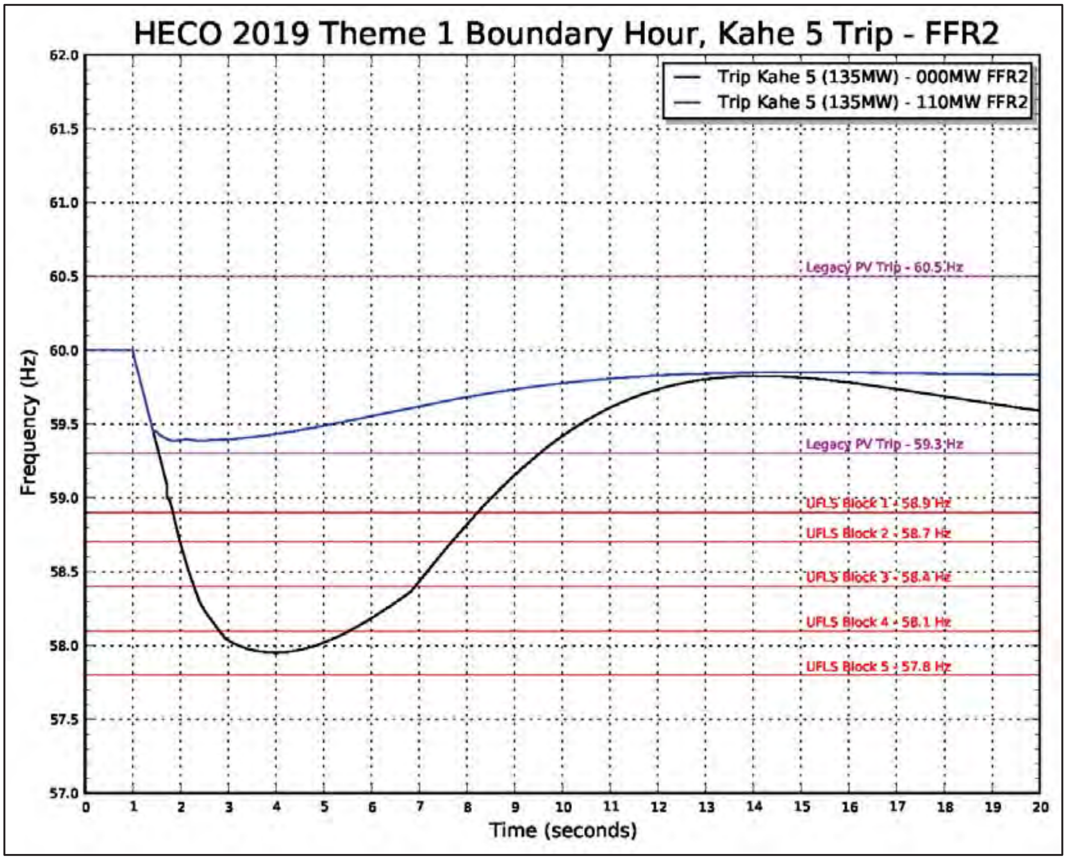

Figure O-29. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-29 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 110 MW.

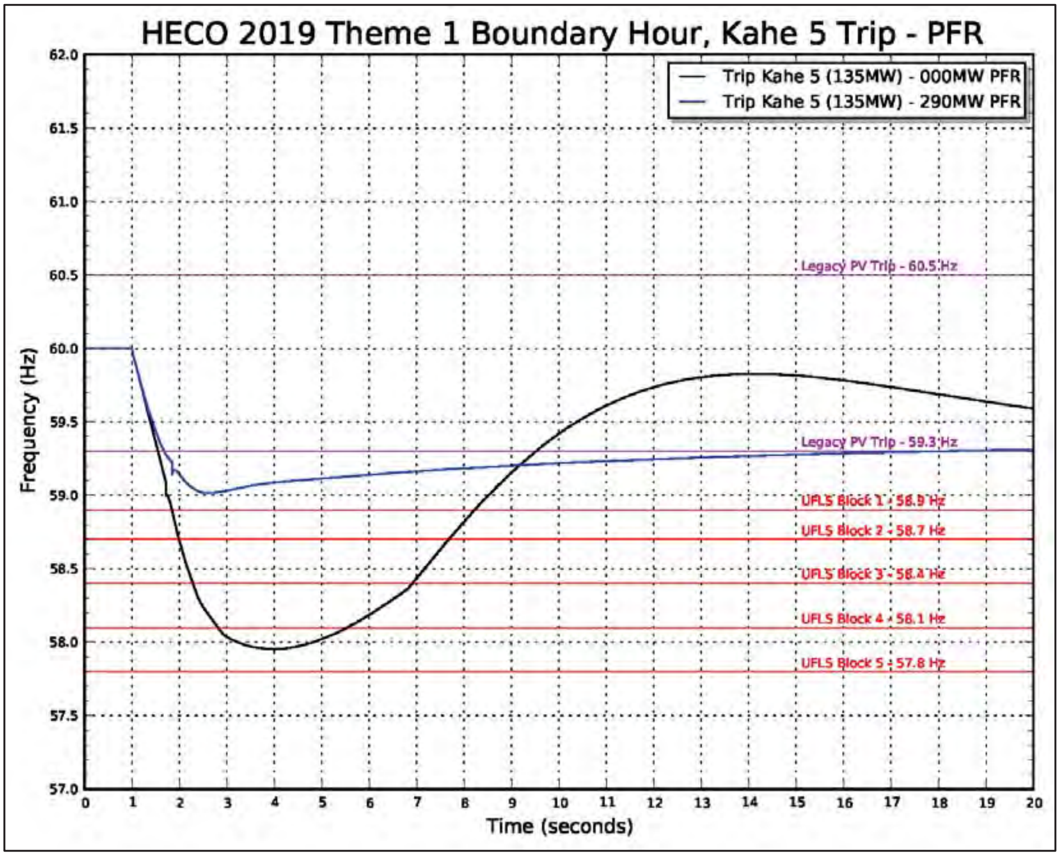

Figure O-30. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-30 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 226 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 6/9/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	27.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	133	0						58		
-Kahuku	30	0						16		
-Kawailoa	69	0						24		
-Na Pua Makani	24	0						15		
-CBRE Wind	10	0						3		
DG-PV	662	0						529		
Station PV	187	0						158		
Total Kinetic Energy								3144		
Total Load								983		
Total Thermal Generation								238		
Total Renewable Generation								745		
Total Generation								983		
Excess Generation								0		
Total Up Regulation								365		
Total Down Regulation								56		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-19. Unit Commitment and Dispatch Fault Analysis

Table O-19 shows the unit commitment and dispatch for the fault analysis.

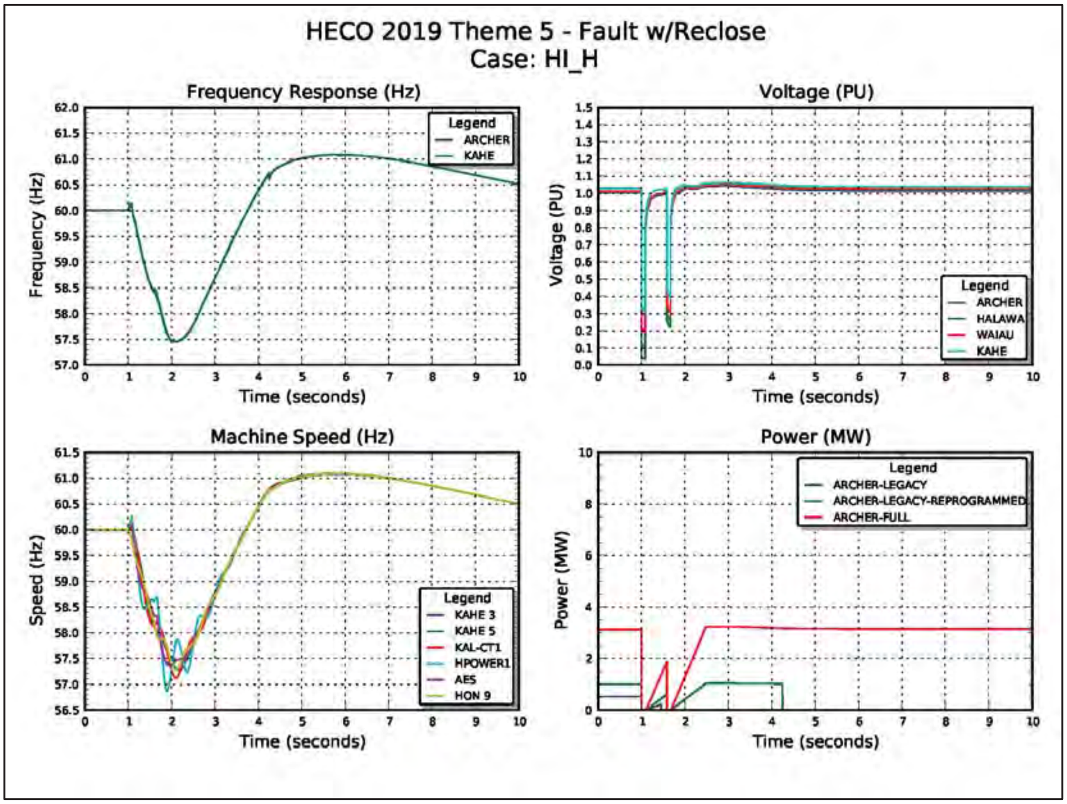

Figure O-31. System Performance for Normally Cleared Fault

Figure O-31 shows the system performance for a normally cleared fault on the Halawa-Iwilei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 687 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from DG-PV is restored but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.5 Hz and avoid system collapse but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system. The under frequency trip protection for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this contingency is 57.5 Hz, providing a 0.5 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001.

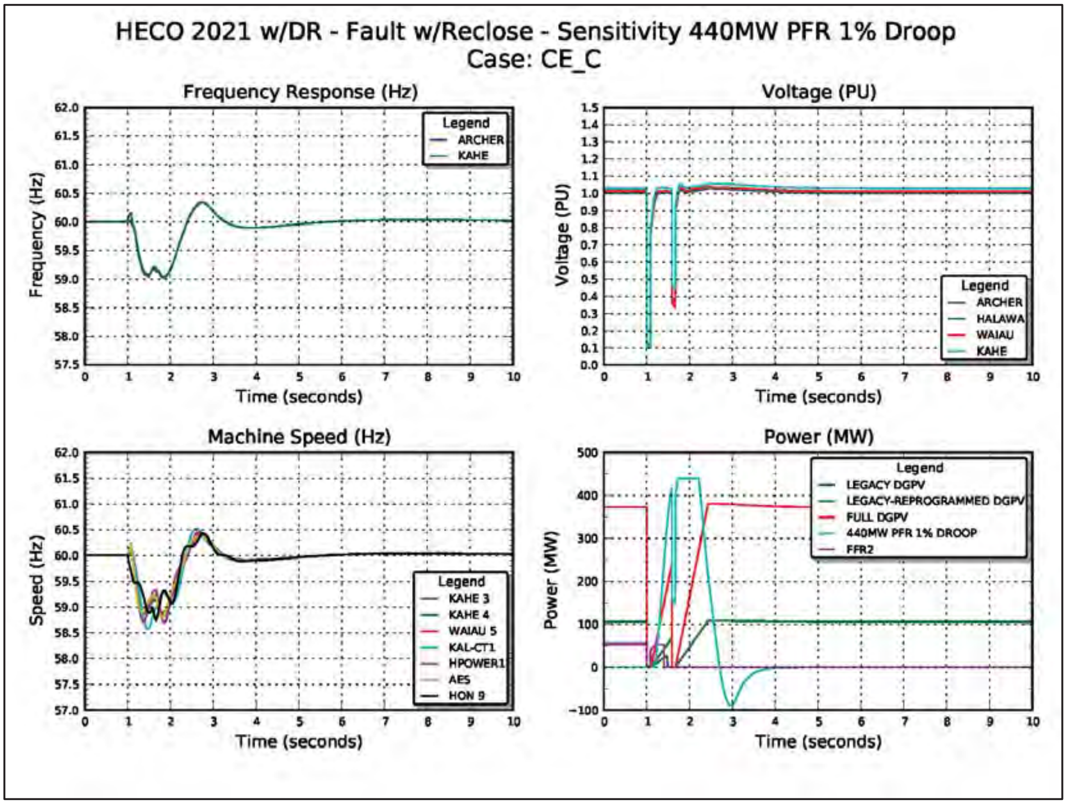

Figure O-32. Normally Cleared Fault Sensitivity 440 MW PFR

Figure O-32 shows system performance with the addition of 440 MW of PFR at 1% droop response. For the purpose of this analysis, a 440 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 440 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

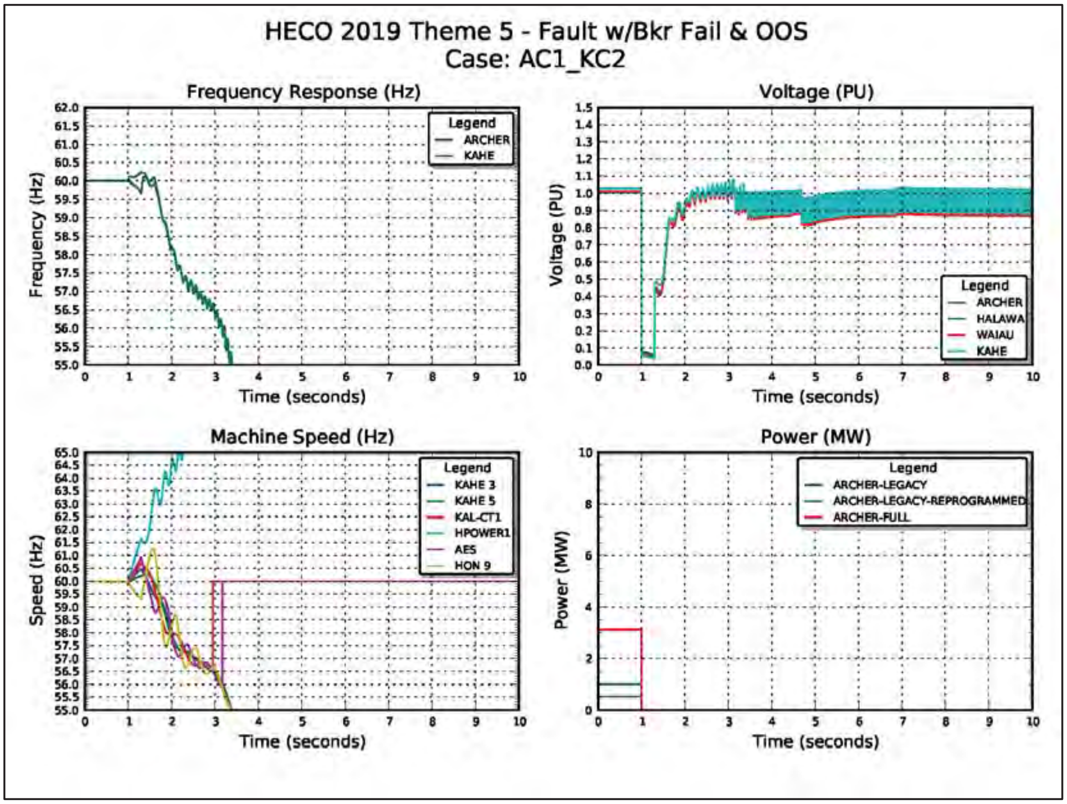

Figure O-33. System Performance for Breaker Failure Analysis

Figure O-33 shows four plots that illustrate system performance for a fault on the AES-CEIP 1 circuit and BKR 276 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the Kahe-CEIP2 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 687 MW of inverter-based generation to trip offline. System frequency decays below 56.0 Hz so the remaining synchronous generators trip offline on under frequency protection, causing the system to collapse. Note that HPOWER 1 loses synchronism almost immediately after the fault, indicating the delayed clearing exceeded its critical clearing time for stability. Further analysis is required to determine if HPOWER 1 requires out-of-step protection.

Fifteen breaker failure simulations resulted in system instability and/or collapse. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize system frequency. The analysis was performed for AES-CEIP 1 circuit only.

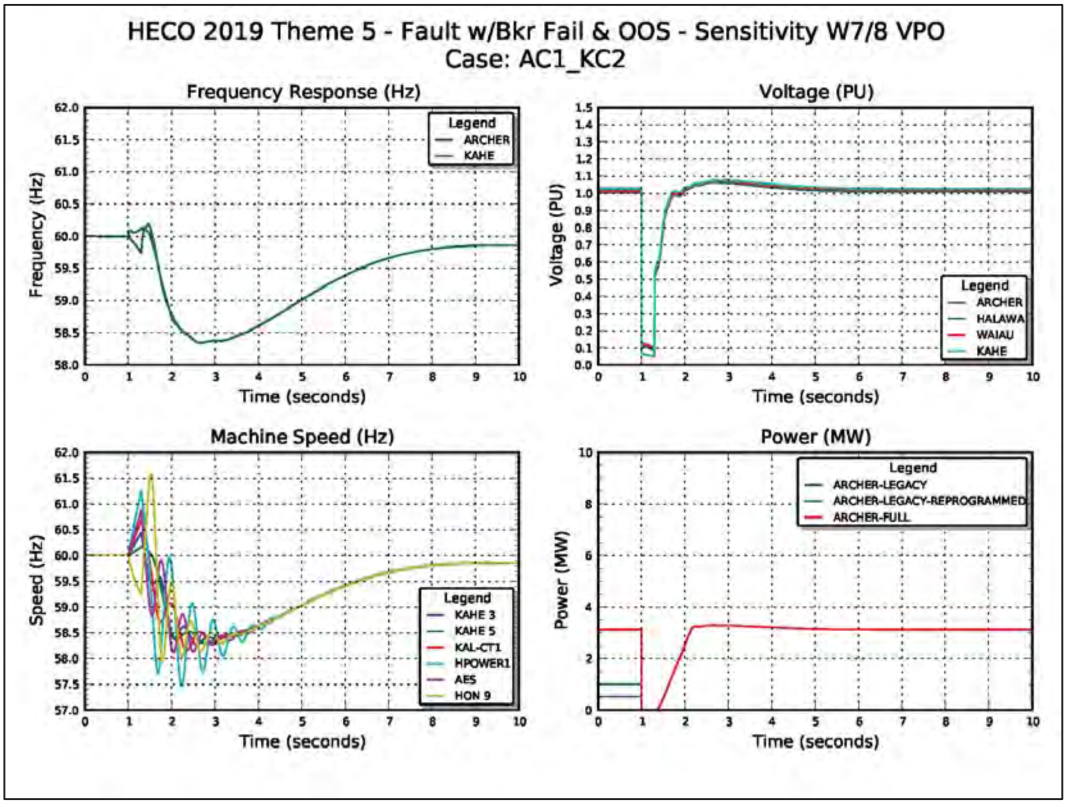

Figure O-34. Breaker Failure Sensitivity VPO Units

Figure O-34 shows system performance with the Waiau Units 7 and 8 operating in VPO. This adds inertia, short circuit current, voltage support/MVAR capability, and increases the magnetic strength of the system. A unit committed in VPO provides limited frequency response reserves.

System voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting. The aggregate response from synchronous units, the restoration of full ride-through DG-PV generation, and four blocks of UFLS stabilizes system frequency at 58.4 Hz. The system is stable but does not meet the requirements of TPL-001. Further analysis is required to determine an optimal strategy to address this issue.

2019 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition	Waiau 7/8 VPO Mitigation
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Stable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-20. Summary of Results Breaker Failure Analysis

Table O-20 is the summary of results for the breaker failure analysis. Fifteen simulations resulted in system instability where HPOWER 1 lost synchronism and/or system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip. Committing Waiau 7 and 8 in VPO stabilized all but two breaker failure simulations.

Multiple blocks of UFLS were required to stabilize system frequency for normally cleared faults. The system requires 440 MW of PFR at 1% droop response to meet TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 10/5/20 Hour 16		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	35.0	5.0	25.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	44.0	38.2	20.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	44.0	38.2	20.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	47.0	39.2	23.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	55.0	30.3	31.4
Kahe 5	134.6	21.0			4.36	158.8	692	107.0	27.6	86.0
Kahe 6	133.8	40.0			4.36	158.8	692	71.0	62.8	31.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163.0	0.0						24.0		
-Kahuku	30.0	0.0						0.0		
-Kawailoa	69.0	0.0						8.0		
-Na Pua Makani	24.0	0.0						0.0		
-CBRE Wind	10.0	0.0						4.0		
-Future Wind	30.0	0.0						12.0		
-Offshore Wind	0.0	0.0								
Total Station PV	362.2	0.0						208.0		
-KS2	5.0	0.0						2.0		
-KREP	5.0	0.0						1.0		
-Waianae	27.6	0.0						12.0		
-Kawailoa PV	49.0	0.0						23.0		
-Mililani 2	14.7	0.0						8.0		
-Waiawa	45.9	0.0						24.0		
-Westloch	20.0	0.0						14.0		
-CBRE PV	15.0	0.0						10.0		
-Future PV	180.0	0.0						114.0		
DG-PV	749.0	0.0						214.0		
Total Kinetic Energy									5637	
Total Load									1247	
Total Thermal Generation									801	
Total Renewable Generation									446	
Total Generation									1247	
Excess Generation									0	
Total Up Regulation									269	
Total Down Regulation									479	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		21.0
	60.5Hz Capacity			215.9				60.5Hz Output		61.7

Table O-21. Unit Commitment and Dispatch 2020 QV Analysis

Table O-21 shows the unit commitment and dispatch for the 2020 QV analysis.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 10/5/20 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	5.4	30.6	-5.4
HPOWER-2	28.0	-16.0	5.4	22.6	-21.4
AES	99.4	-49.8	34.1	65.3	-83.9
Kalaeloa CT-1	84.5	-35.9	20.2	64.3	-56.1
Kalaeloa ST	84.5	-35.8	20.2	64.3	-56.0
Kalaeloa CT-2	42.1	-16.7	20.2	21.9	-36.9
Kahe 1	62.9	-49.7	20.4	42.5	-70.1
Kahe 2	62.9	-49.7	20.4	42.5	-70.1
Kahe 3	68.3	-18.3	20.4	47.9	-38.7
Kahe 4	60.6	-16.3	20.4	40.2	-36.7
Kahe 5	91.9	-61.3	94.9	-3.0	-156.2
Kahe 6	106.6	-61.3	38.6	68.0	-99.9
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	26.0	25.0	-59.0
Hon 9 (Sync Cond)	51.0	-33.0	26.0	25.0	-59.0
Total Wind	96.7	-120.3	13.4	49.1	-100.3
-Kahuku	17.9	-17.9			
-Kawailoa	50.0	-74.5	13.3	36.7	-87.8
-Na Pua Makani	16.4	-15.4			
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.1	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	234.4	-234.4	22.8	211.6	-257.2
-KS2	1.6	-1.6	1.3	0.4	-2.9
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	2.5	12.0	-17.0
-Kawailoa PV	36.8	-36.8	-0.9	37.7	-35.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	1.2	31.6	-34.1
-Westloch	6.3	-6.3	3.3	3.0	-9.5
-CBRE PV	4.7	-4.7	0.0	4.6	-4.7
-Future PV	125.0	-125.0	13.6	111.4	-138.6
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			372.7		
Total Renewable MVAR Generation			36.2		
Total Cap Bank MVAR			184.2		
Charging MVAR			76.5		
Total MVAR Supply			669.5		
Total MVAR Load			404.6		
Total MVAR Losses			264.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				817.8	
Total MVAR Absorb Capability					-1207.0

Table O-22. MVAR Capability 2020 QV Analysis

Table O-22 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-23. N-2 Contingencies 2020

Table O-23 shows the N-2 contingencies that were simulated in the QV analysis. These contingencies have the biggest impact to MVAR requirements for the critical busses.

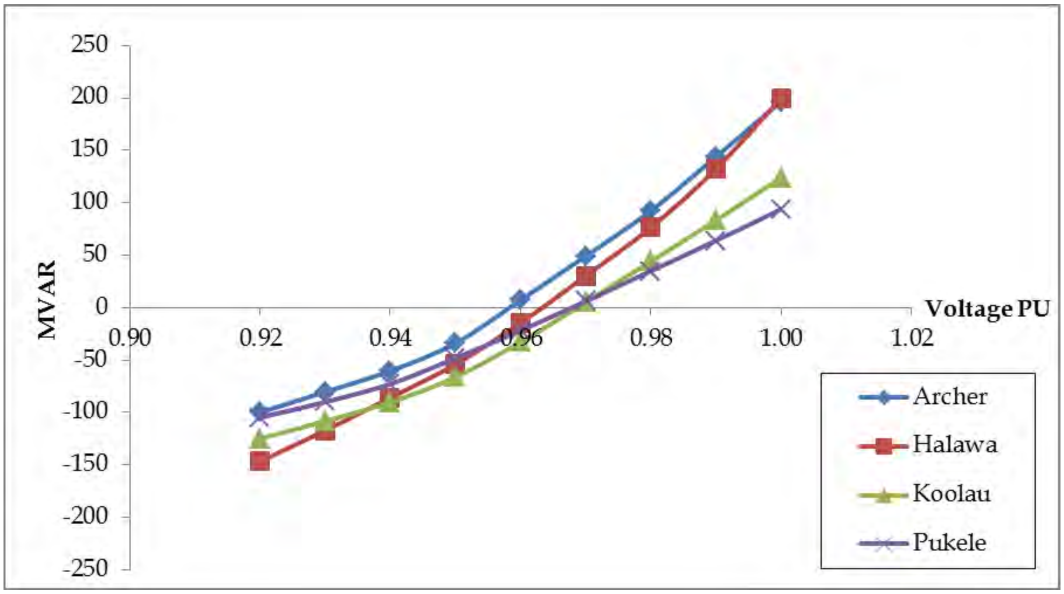

Figure O-35. QV Curves 2020

Figure O-35 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	196	125	144	125	92	154	49	154	7	154	-34	135	-60	135	-80	135	-100
120	Halawa	125	200	125	132	154	76	154	30	154	-15	154	-54	154	-86	154	-117	154	-147
150	Koolau	125	124	125	83	125	44	125	5	125	-33	125	-66	316	-90	203	-108	203	-125
170	Pukele	125	94	125	64	125	35	125	6	125	-22	125	-48	125	-73	316	-90	203	-105

Table O-24. Summary of Results 2020 QV Analysis

Table O-24 shows the unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Analysis was performed on two hours from the Theme 5 production simulation data that represent a typical and a boundary condition.

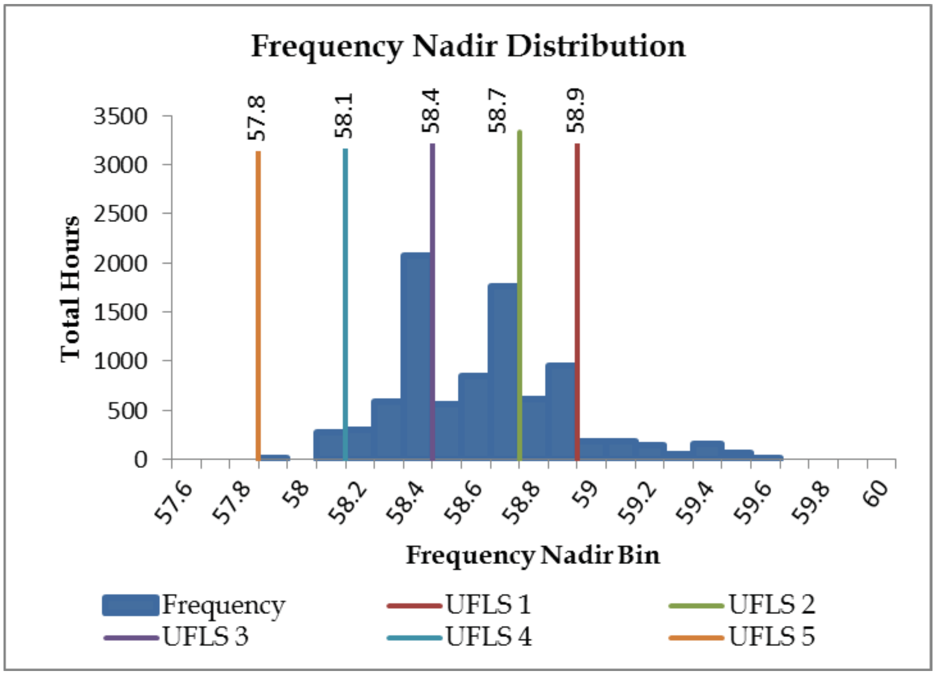

Figure O-36. Frequency Nadir Histogram 2020

Figure O-36 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2076 hours was 4:00 PM on Monday, August 17. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 271 hours was 10:00 AM on Thursday, December 24. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

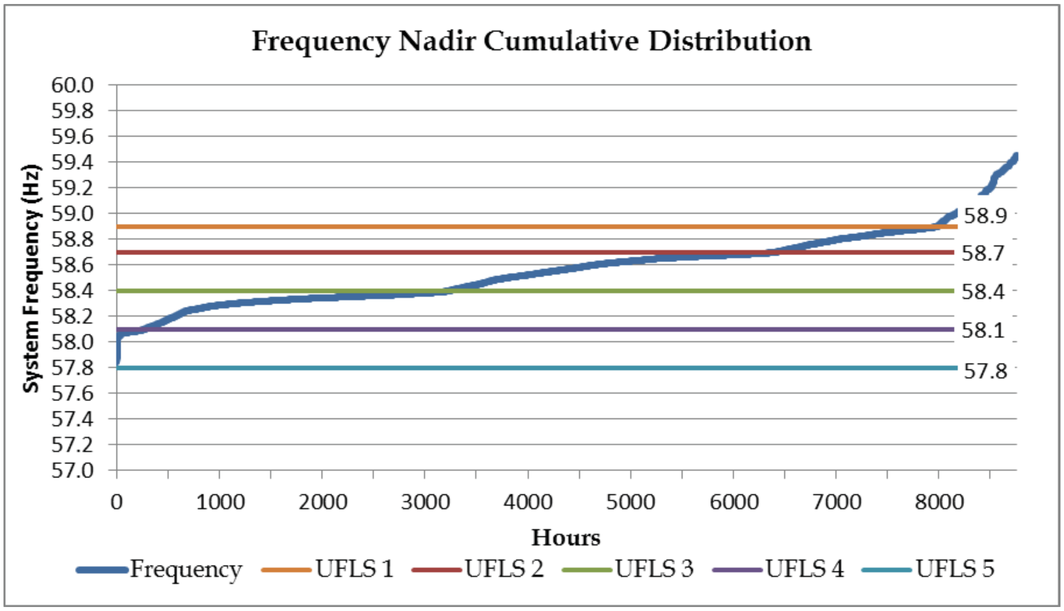

Figure O-37. Frequency Nadir Duration Curve 2020

Figure O-37 shows the frequency nadir duration curve for 2020. The system is at risk of UFLS for 7960 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Mon 8/17/20 Hour 16			Theme 5 - AES Trip Boundary Thu 12/24/20 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.8	11.2	18.8	22.0	18.0	12.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.5	55.7	2.7			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						53			16		
-Kahuku	30	0						9			1		
-Kawailoa	69	0						20			7		
-Na Pua Makani	24	0						16			0		
-CBRE Wind	10	0						2			2		
DG-PV	749	0						411			206		
Station PV	363	0						288			214		
Total Kinetic Energy								4161			3378		
Total Load								1226			824		
Total Thermal Generation								474			387		
Total Renewable Generation								752			436		
Total Generation								1226			824		
Excess Generation								0			0		
Total Up Regulation								293			213		
Total Down Regulation								240			200		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		40.3	59.3Hz Output		20.3
	60.5Hz Capacity			215.9				60.5Hz Output		118.4	60.5Hz Output		59.5

Table O-25. Unit Commitment and Dispatch 2020

Table O-25 shows the unit commitment and dispatch for the typical hour (8/17/20, 4:00 PM) and boundary hour (12/24/20, 10:00 AM).

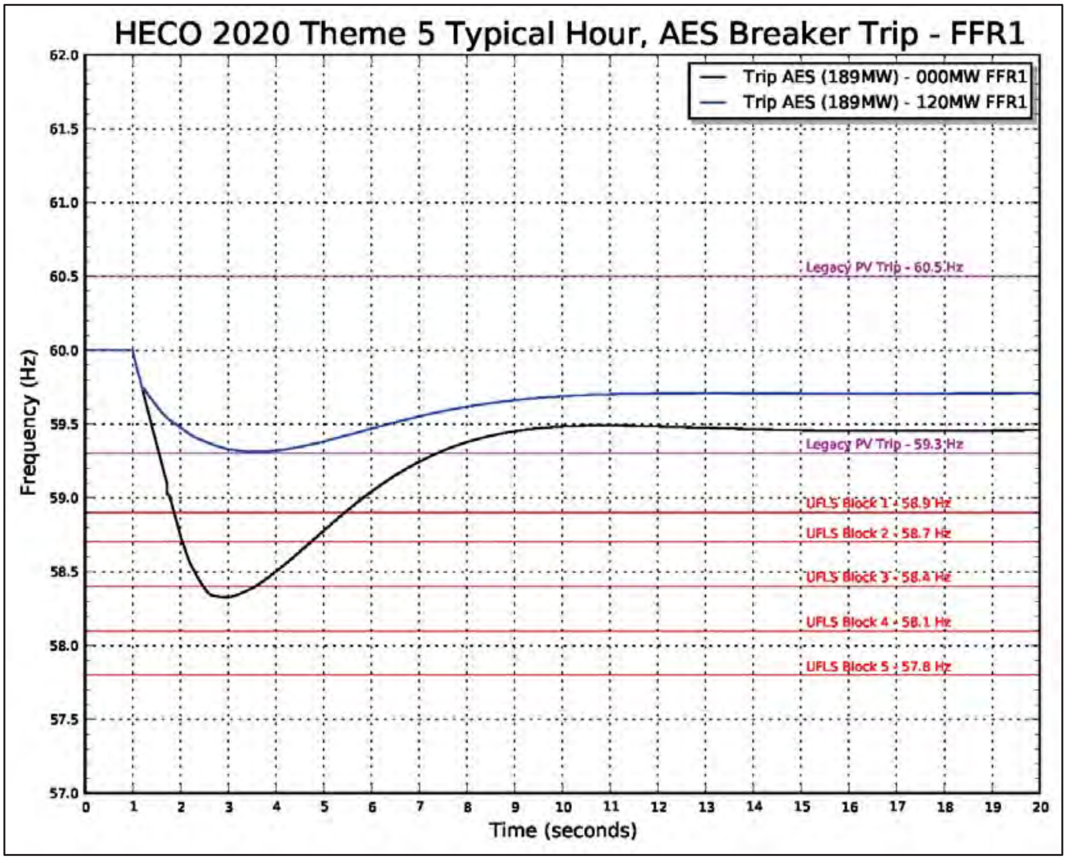

Figure O-38. Frequency Response Profile FFR1 Typical Hour

Figure O-38 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4161 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.3 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

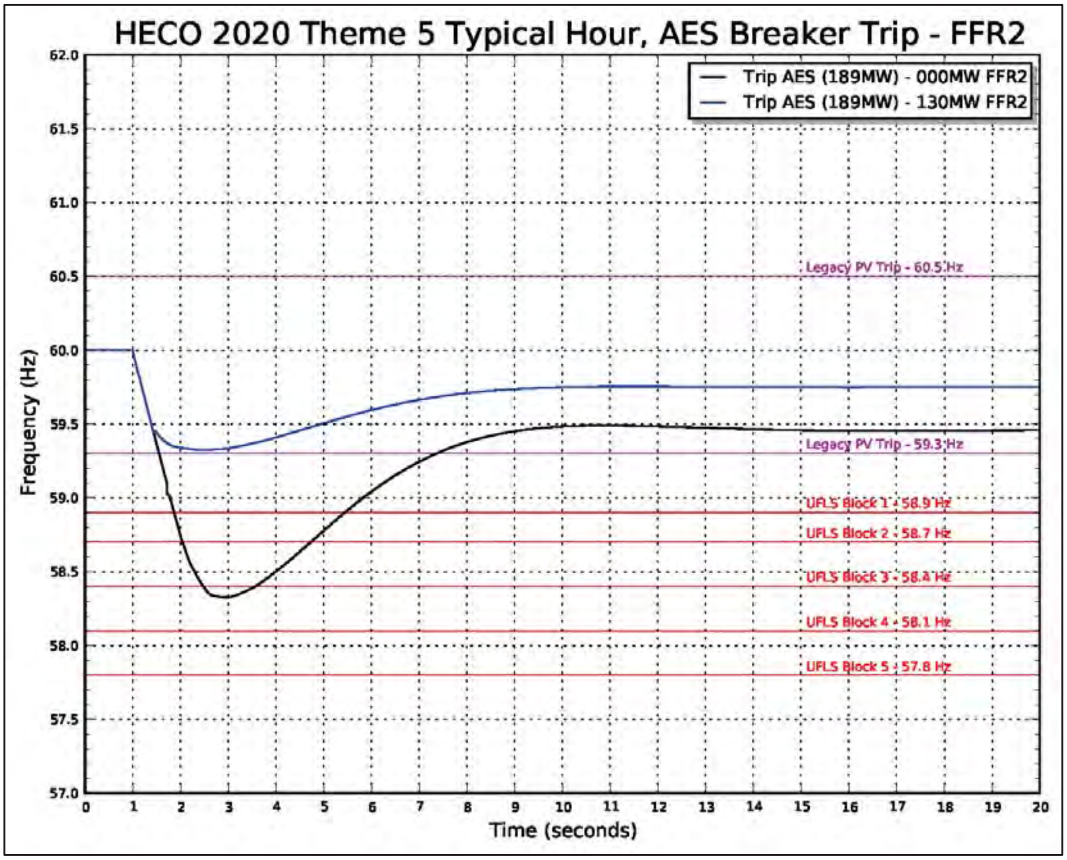

Figure O-39. Frequency Response Profile FFR2 Typical Hour

Figure O-39shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

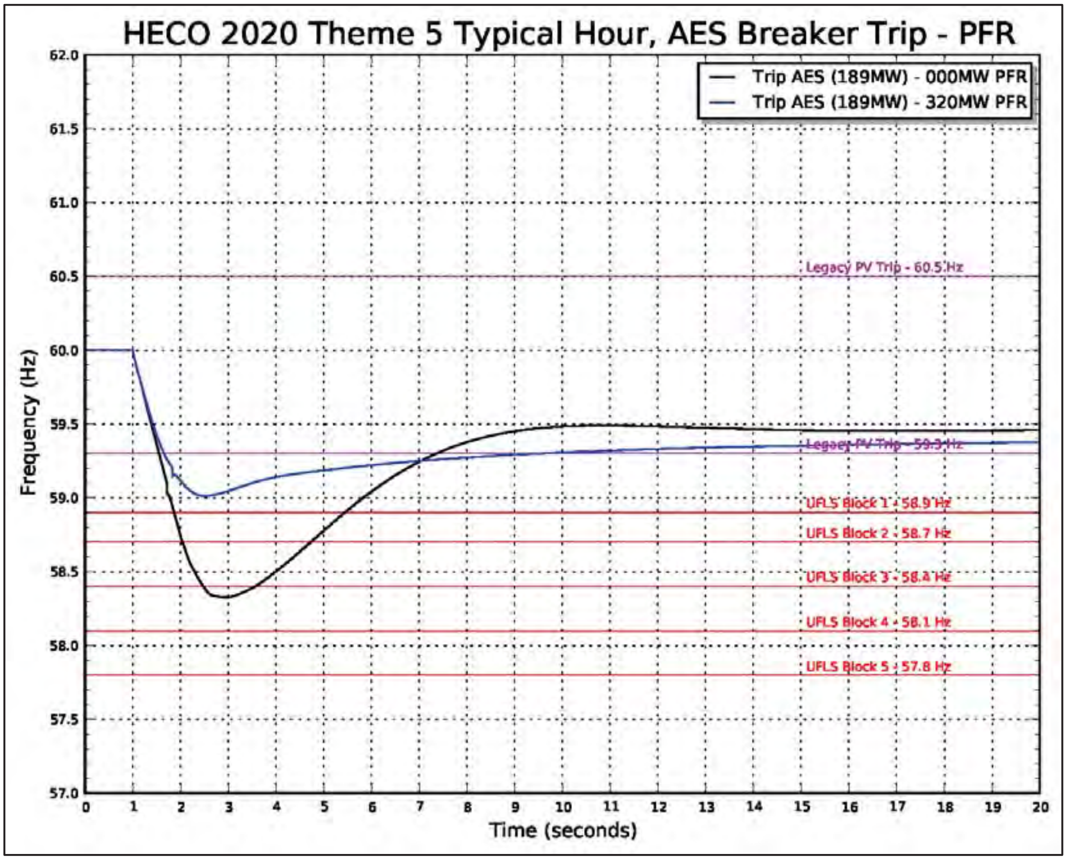

Figure O-40. Frequency Response Profile PFR Typical Hour

Figure O-40 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 320 MW. This is in addition to the 293 MW of upward regulation from thermal generation.

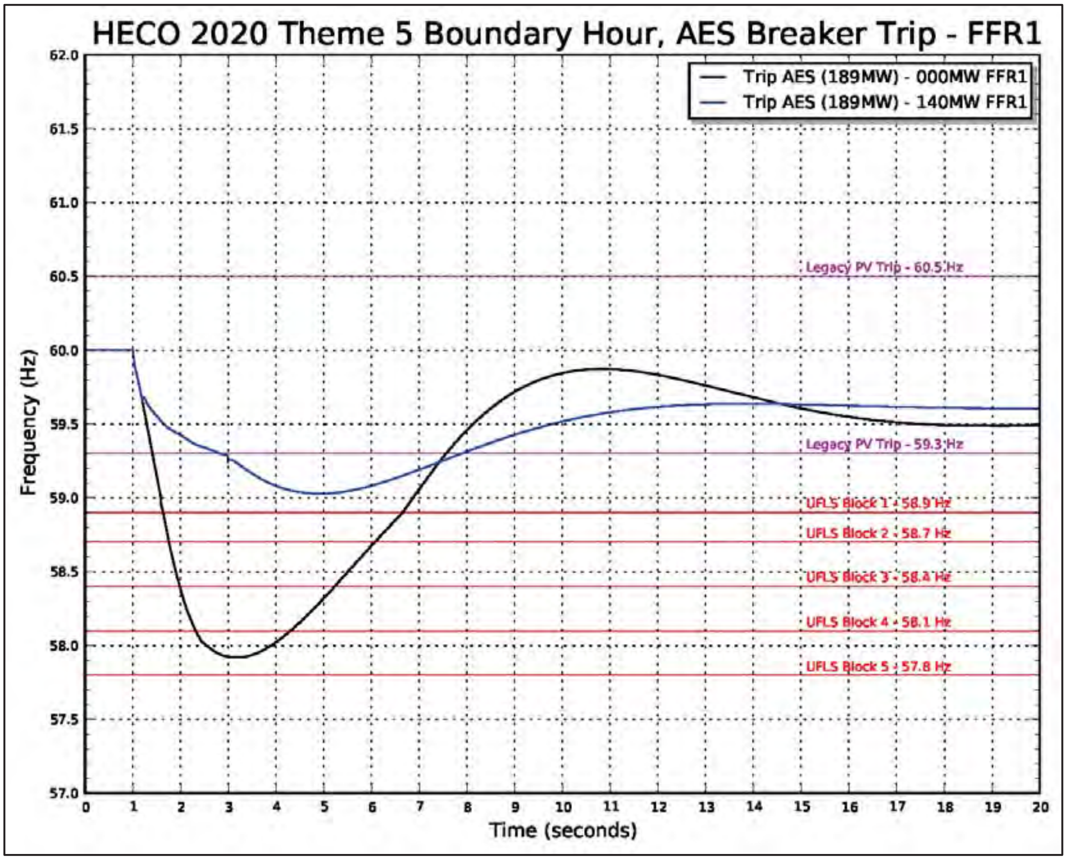

Figure O-41. Frequency Response Profile FFR1 Boundary Hour

Figure O-41 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 20.3 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

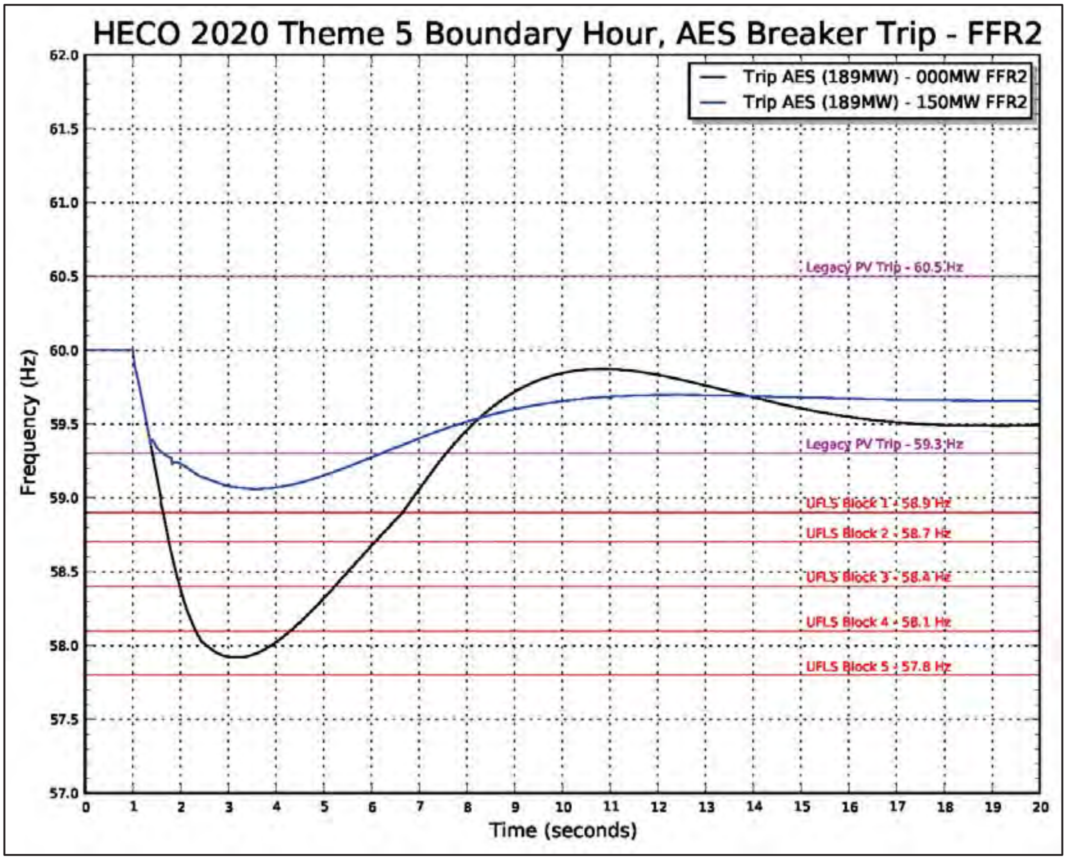

Figure O-42. Frequency Response Profile FFR2 Boundary Hour

Figure O-42 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

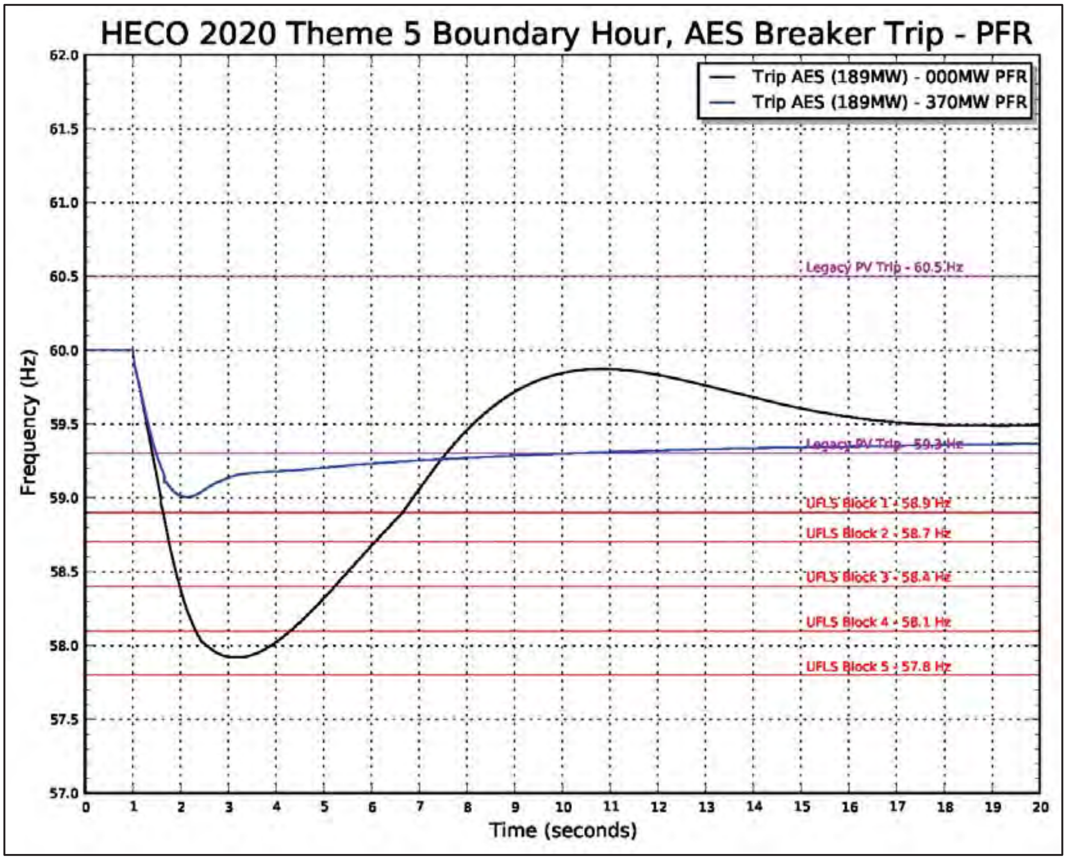

Figure O-43. Frequency Response Profile PFR Boundary Hour

Figure O-43 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 370 MW. This is in addition to the 213 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Mon 8/17/20 Hour 16			Theme 5 - K5 Trip Boundary Thu 12/24/20 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	75.0	114.0	12.0	75.0	114.0	12.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.8	11.2	18.8	22.0	18.0	12.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.5	55.7	2.7			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						53			16		
-Kahuku	30	0						9			1		
-Kawailoa	69	0						20			7		
-Na Pua Makani	24	0						16			0		
-CBRE Wind	10	0						2			2		
DG-PV	749	0						411			206		
Station PV	363	0						288			214		
Total Kinetic Energy								4161			3378		
Total Load								1226			824		
Total Thermal Generation								474			387		
Total Renewable Generation								752			436		
Total Generation								1226			823		
Excess Generation								0			0		
Total Up Regulation								294			213		
Total Down Regulation								240			200		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		40.3	59.3Hz Output		20.3
	60.5Hz Capacity			215.9				60.5Hz Output		118.4	60.5Hz Output		59.5

Table O-26. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-26 shows the unit commitment and dispatch for the typical hour (8/17/20, 4:00 PM) and boundary hour (12/24/20, 10:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

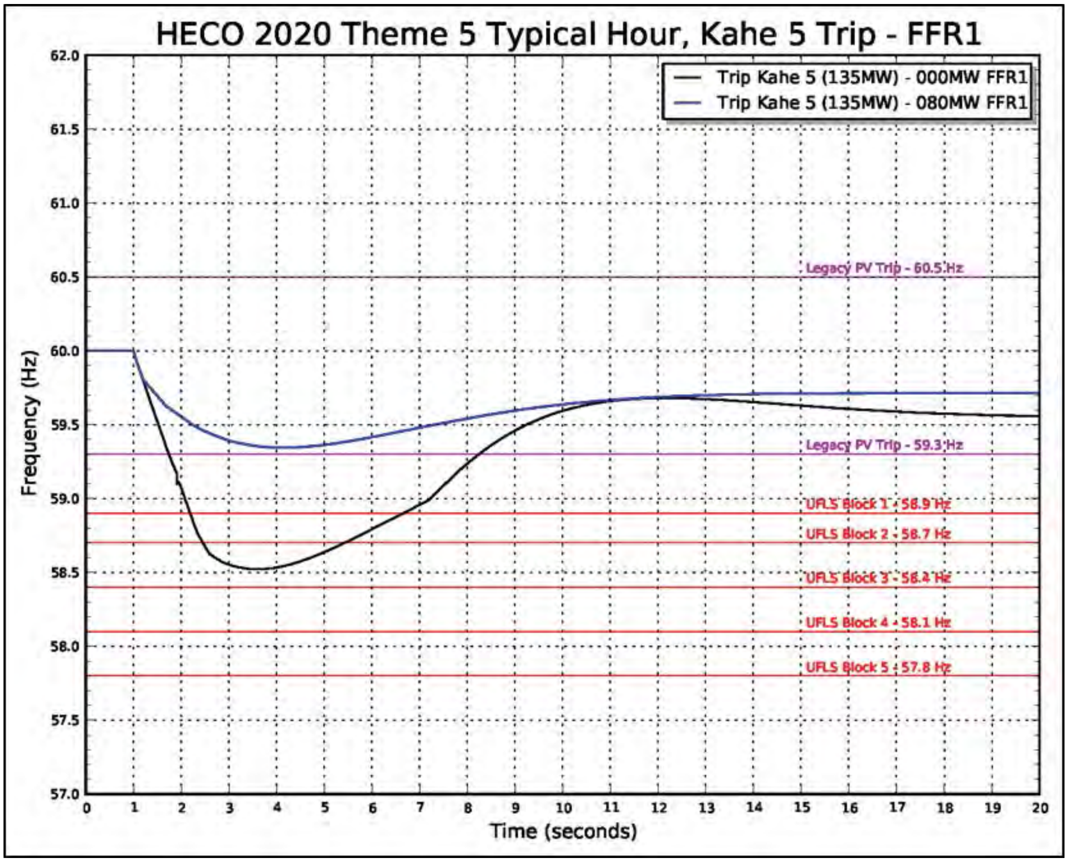

Figure O-44. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-44 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4161 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.3 MW. With no FFR, the frequency nadir approaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 80 MW.

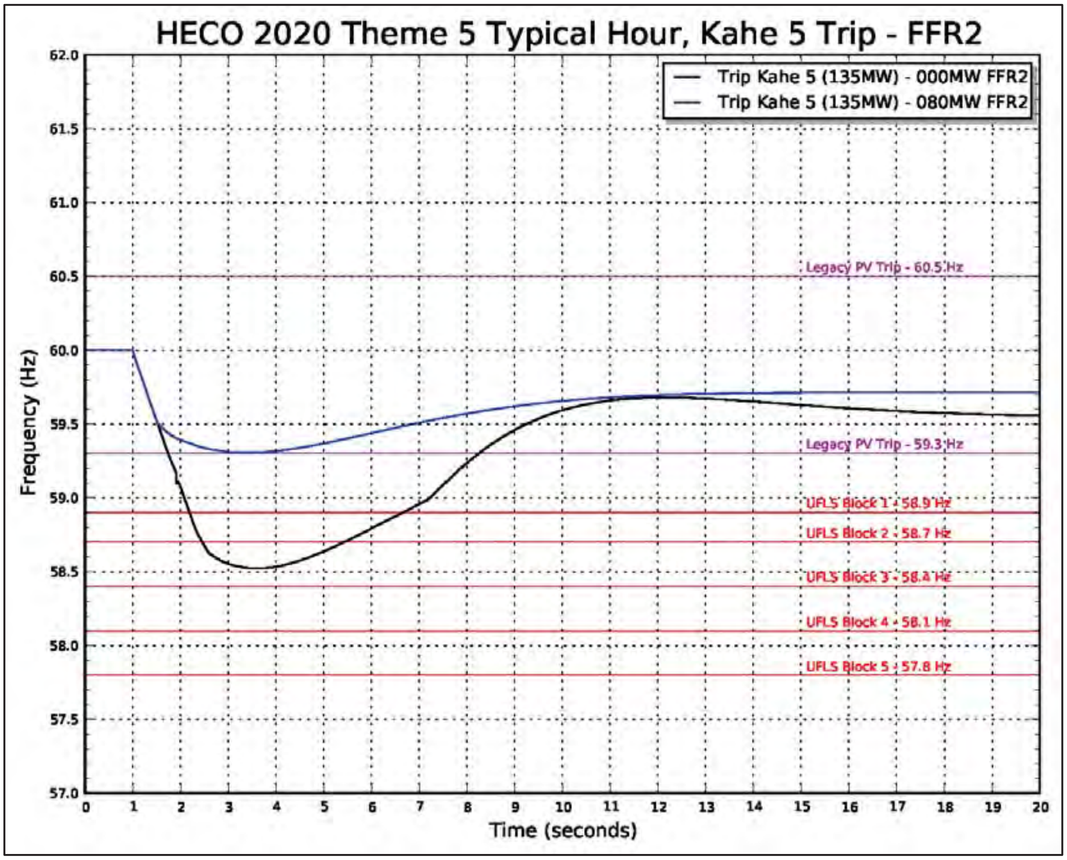

Figure O-45. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-45 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 80 MW.

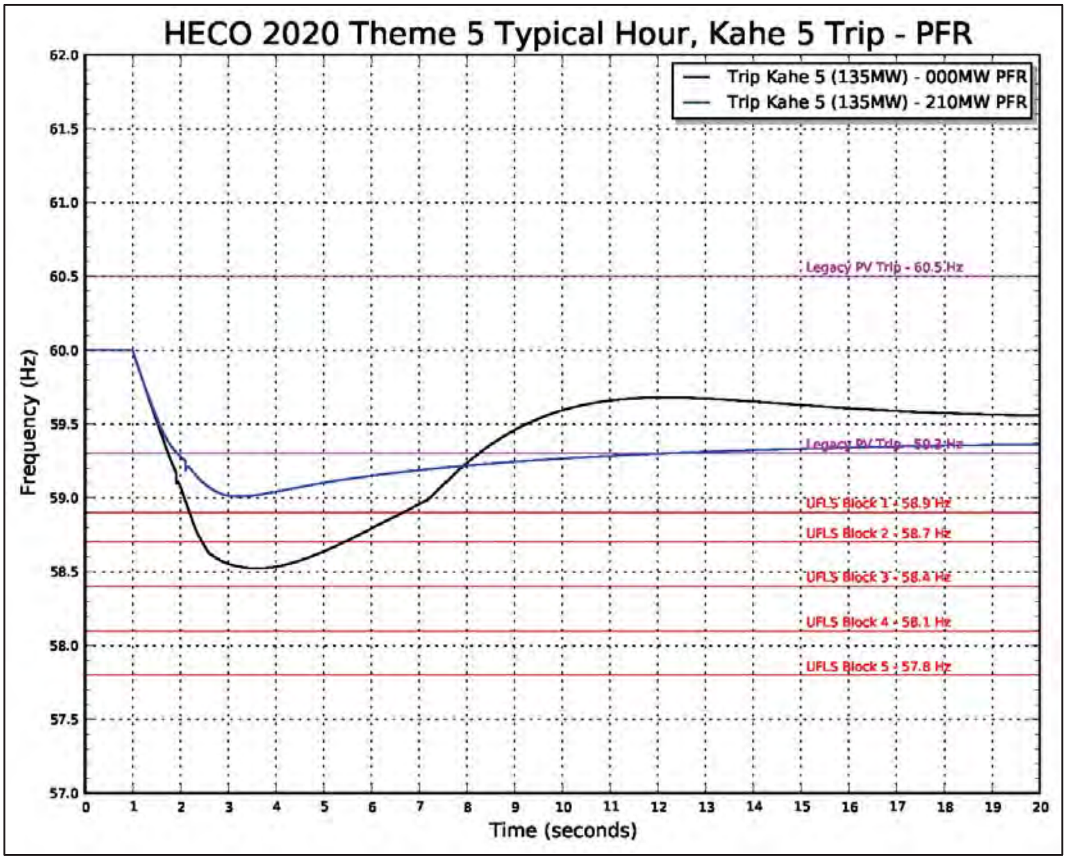

Figure O-46. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-46 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 210 MW. This is in addition to the 294 MW of upward regulation from thermal generation.

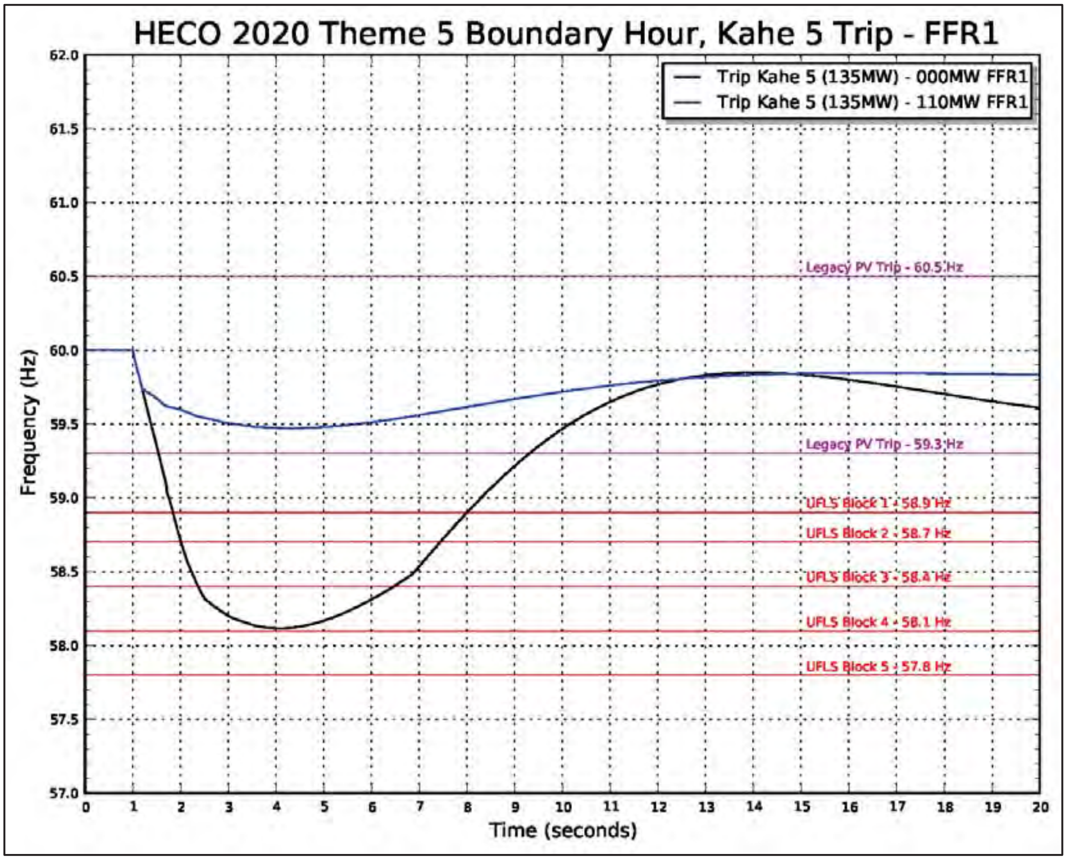

Figure O-47. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-47 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 20.3 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

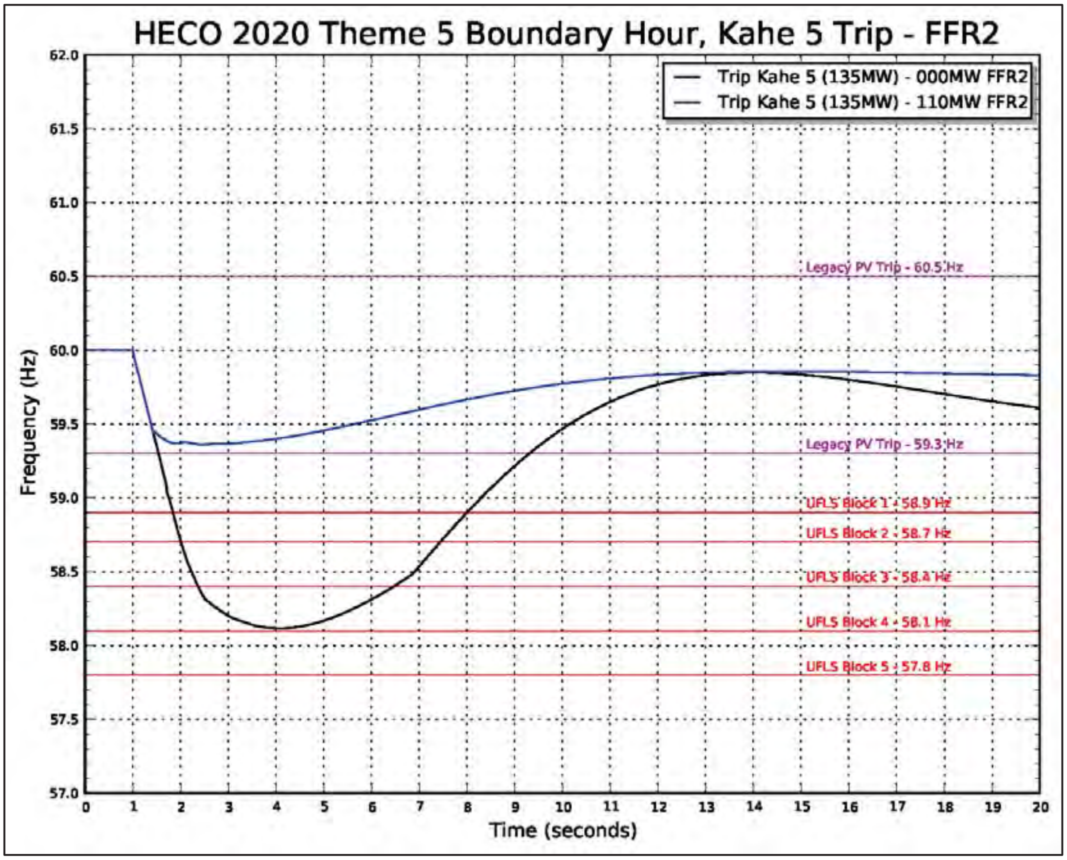

Figure O-48. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-48 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 110 MW.

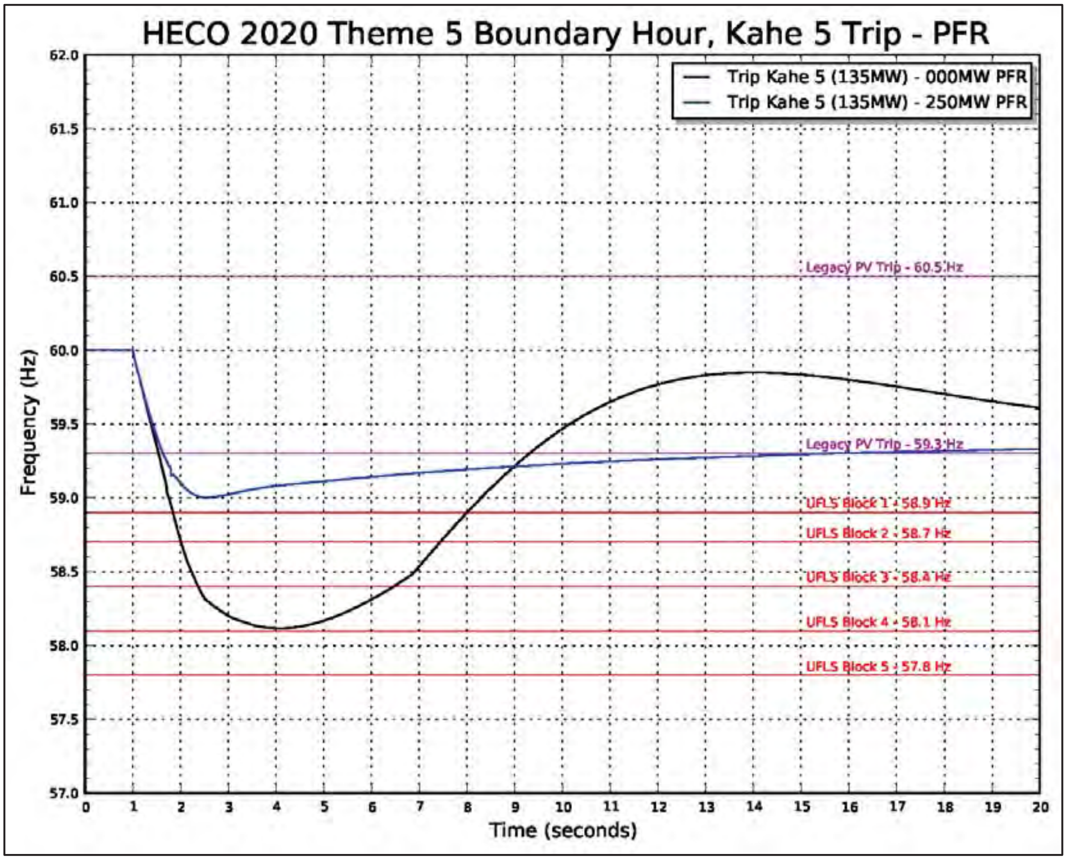

Figure O-49. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-49 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 250 MW. This is in addition to the 213 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 6/7/20 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	50.9	33.1	21.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.1	27.9	2.1
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						66		
-Kahuku	30	0						17		
-Kawailoa	69	0						25		
-Na Pua Makani	24	0						15		
-CBRE Wind	10	0						0		
DG-PV	693	0						549		
Station PV	367	0						186		
Total Kinetic Energy									2094	
Total Load									989	
Total Thermal Generation									189	
Total Renewable Generation									800	
Total Generation									989	
Excess Generation									0	
Total Up Regulation									192	
Total Down Regulation									52	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-27. Unit Commitment and Dispatch Fault Analysis

Table O-27 shows the unit commitment and dispatch for the fault analysis.

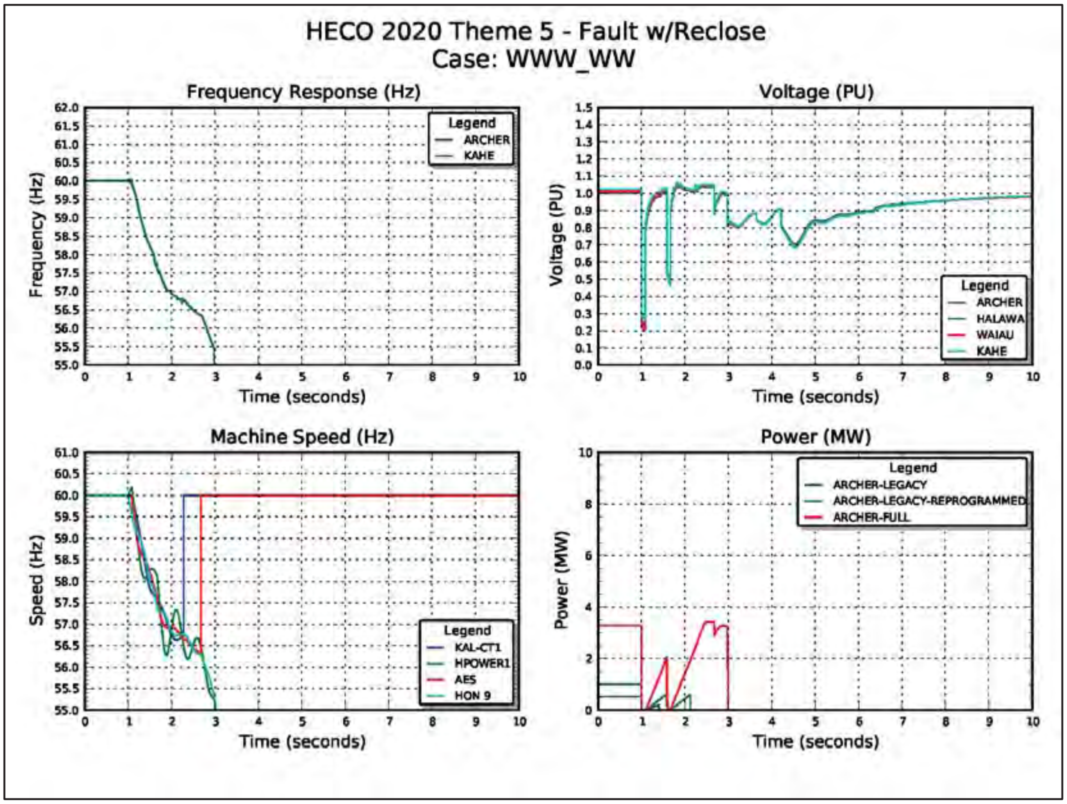

Figure O-50. System Performance for Normally Cleared Fault

Figure O-50 shows the system performance for a normally cleared fault on the Waiau-Wahiawa circuit, which is the only simulation that resulted in system collapse. System voltage is suppressed below the 0.5 PU threshold where the 735 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz. The remaining synchronous units trip on under frequency protection, causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

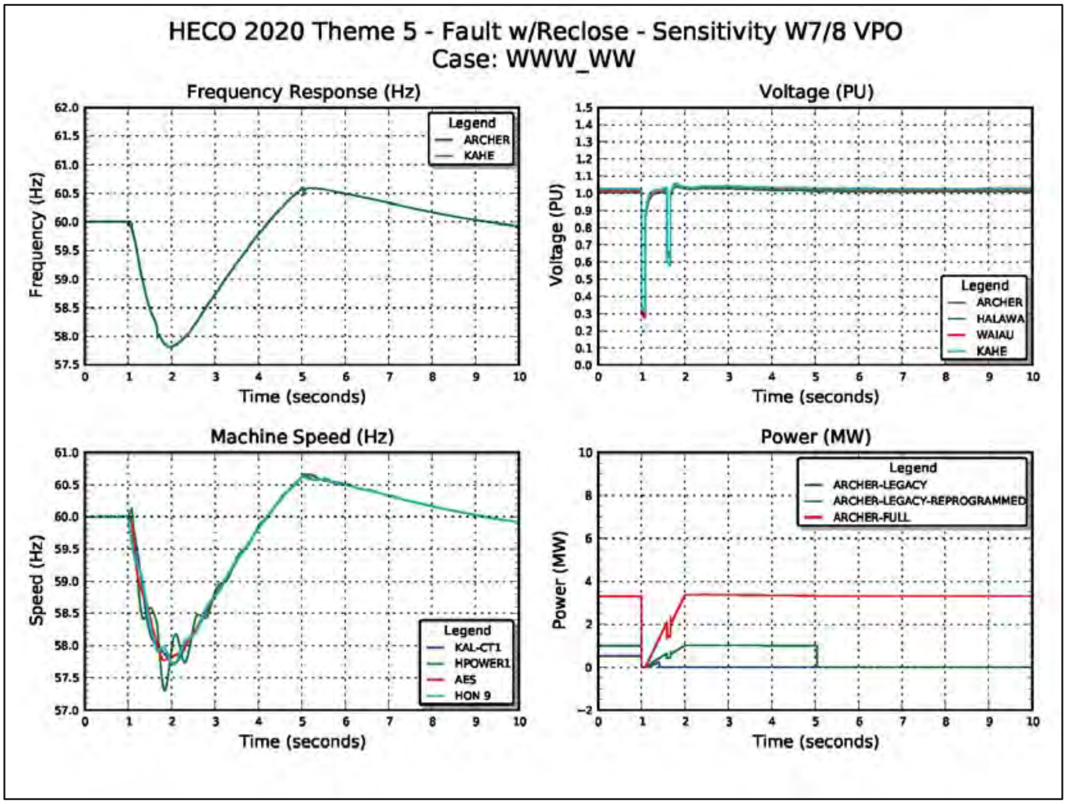

Figure O-51. Normally Cleared Fault Sensitivity Analysis VPO Units

Figure O-51 shows system performance with Waiau Units 7 and 8 operating in VPO. The VPO units add inertia, MVAR/voltage support at the load center, and increases the magnetic strength of the system. With the thermal units remaining online, system voltage recovers and most of the DG-PV generation is restored. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.8 Hz.

The system does not meet the requirements of TPL-001. Non-exhaustive sensitivity analyses were performed to bring the system into compliance with TPL-001.

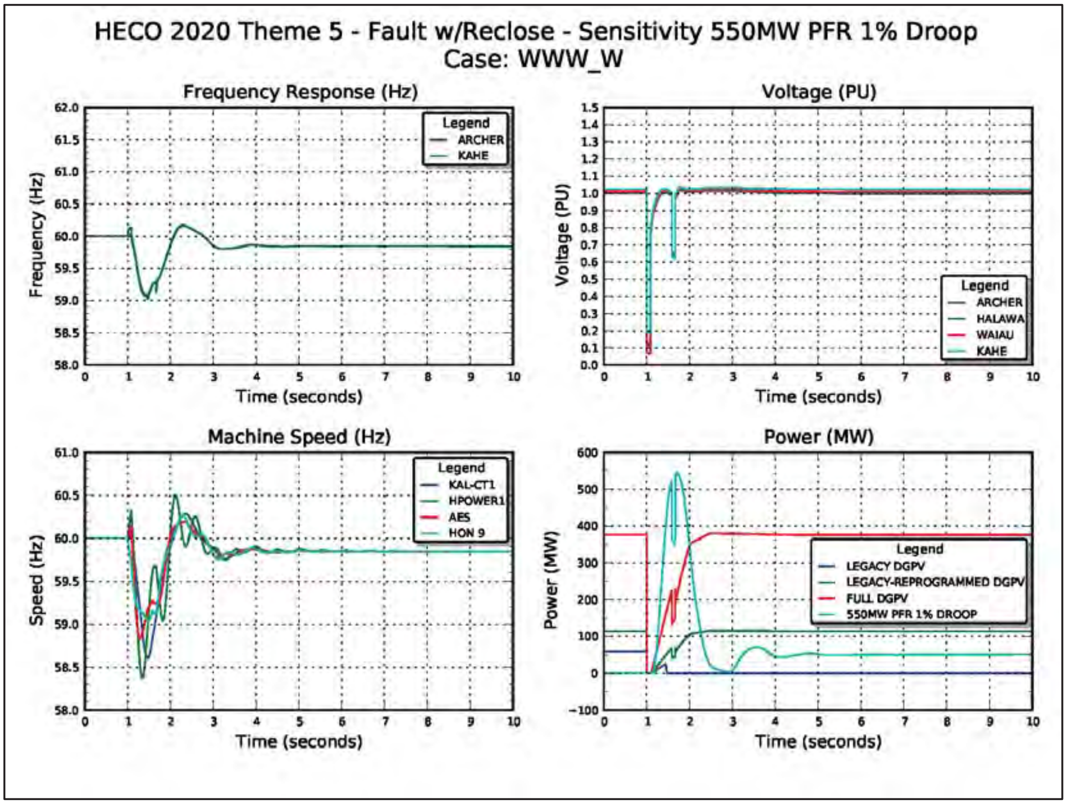

Figure O-52. Normally Cleared Fault Sensitivity Analysis 550 PFR

Figure O-52 shows system performance with the addition of the 550 MW of PFR at 1% droop response. For the purpose of this analysis, a 550 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 550 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

2020 138 kV Fault Analysis				
Circuit Outage	**Reclose TD**	**System Status**	**Waiau 7/8 VPO Mitigation**	**550 MW PFR Mitigation**
CEIP-Ewa Nui	30	Stable	Stable	Stable
Halawa-Iwilei	30	Stable	Stable	Stable
Halawa-Koolau	30	Stable	Stable	Stable
Halawa-School	30	Stable	Stable	Stable
Kahe-CEIP 1	30	Stable	Stable	Stable
Kahe-CEIP 2	30	Stable	Stable	Stable
Kalaeloa-Ewa Nui	30	Stable	Stable	Stable
Kahe-Halawa 1	30	Stable	Stable	Stable
Kahe-Halawa 2	30	Stable	Stable	Stable
Kahe-Waiau	30	Stable	Stable	Stable
Makalapa-Airport	30	Stable	Stable	Stable
Waiau-Ewa Nui 1	30	Stable	Stable	Stable
Waiau-Ewa Nui 2	30	Stable	Stable	Stable
Waiau-Koolau 1	30	Stable	Stable	Stable
Waiau-Koolau 2	30	Stable	Stable	Stable
Waiau-Makalapa 1	30	Stable	Stable	Stable
Waiau-Makalapa 2	30	Stable	Stable	Stable
Waiau-Wahiawa	30	Unstable	Stable	Stable

Table O-28. Summary of Results Normal Clearing Fault Analysis

Table O-28 shows the results of the normal clearing fault analysis. A fault on the Waiau-Wahiawa circuit resulted in system instability where system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to disconnect from the system. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency for this contingency event but multiple blocks of UFLS was also required to stabilize system frequency.

The system requires 550 MW of PFR at 1% droop response to meet TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 7/19/21 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	13.0	VPO	VPO
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	40.0	42.2	16.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	42.0	44.2	18.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	53.0	32.3	29.4
Kahe 5	134.6	21.0			4.36	158.8	692	99.0	35.6	78.0
Kahe 6	133.8	40.0			4.36	158.8	692	71.0	62.8	31.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163.0	0.0						62.0		
-Kahuku	30.0	0.0						21.0		
-Kawailoa	69.0	0.0						30.0		
-Na Pua Makani	24.0	0.0						3.0		
-CBRE Wind	10.0	0.0						2.0		
-Future Wind	30.0	0.0						6.0		
-Offshore Wind	0.0	0.0								
Total Station PV	462.2	0.0						197.0		
-KS2	5.0	0.0						1.0		
-KREP	5.0	0.0						3.0		
-Waianae	27.6	0.0						15.0		
-Kawailoa PV	49.0	0.0						35.0		
-Mililani 2	14.7	0.0						9.0		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						9.0		
-CBRE PV	15.0	0.0						5.0		
-Future PV	280.0	0.0						90.0		
DG-PV	791.0	0.0						222.0		
Total Kinetic Energy									5637	
Total Load									1241	
Total Thermal Generation									760	
Total Renewable Generation									481	
Total Generation									1241	
Excess Generation									0	
Total Up Regulation									241	
Total Down Regulation									449	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		20.6
	60.5Hz Capacity			215.9				60.5Hz Output		60.6

Table O-29. Unit Commitment and Dispatch 2021 QV Analysis

Table O-29 shows the unit commitment and dispatch for the 2021 QV analysis.

Unit	Unit Ratings		Theme 5 - QV Dispatch Mon 7/19/21 Hour 17		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	5.4	30.6	-5.4
HPOWER-2	28.0	-16.0	5.4	22.6	-21.4
AES	99.4	-49.8	32.4	67.0	-82.2
Kalaeloa CT-1	84.5	-35.9	19.6	64.9	-55.5
Kalaeloa ST	84.5	-35.8	19.6	64.9	-55.4
Kalaeloa CT-2	42.1	-16.7	19.6	22.5	-36.3
Kahe 1	70.2	-52.0	19.6	50.6	-71.6
Kahe 2	64.4	-50.3	19.6	44.8	-69.9
Kahe 3	69.7	-19.7	19.6	50.1	-39.3
Kahe 4	61.5	-16.8	19.6	41.9	-36.4
Kahe 5	95.6	-62.9	94.5	1.1	-157.5
Kahe 6	106.6	-61.3	38.6	68.0	-99.9
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	25.1	25.9	-58.1
Hon 9 (Sync Cond)	51.0	-33.0	25.1	25.9	-58.1
Total Wind	96.7	-120.3	14.9	81.9	-135.2
-Kahuku	17.9	-17.9	6.2	11.7	-24.0
-Kawailoa	50.0	-74.5	8.6	41.4	-83.1
-Na Pua Makani	16.4	-15.4	0.1	16.3	-15.5
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.4	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	234.4	-234.4	20.8	213.6	-255.2
-KS2	1.6	-1.6	1.3	0.3	-2.9
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	2.5	12.0	-17.0
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	1.3	31.6	-34.2
-Westloch	6.3	-6.3	3.2	3.0	-9.5
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	125.0	-125.0	11.3	113.7	-136.3
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			363.6		
Total Renewable MVAR Generation			35.7		
Total Cap Bank MVAR			184.7		
Charging MVAR			76.7		
Total MVAR Supply			660.6		
Total MVAR Load			402.8		
Total MVAR Losses			257.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				876.5	
Total MVAR Absorb Capability					-1237.2

Table O-30. MVAR Capability 2021 QV Analysis

Table O-30 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-31. N-2 Contingencies 2021 QV Analysis

Table O-31 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

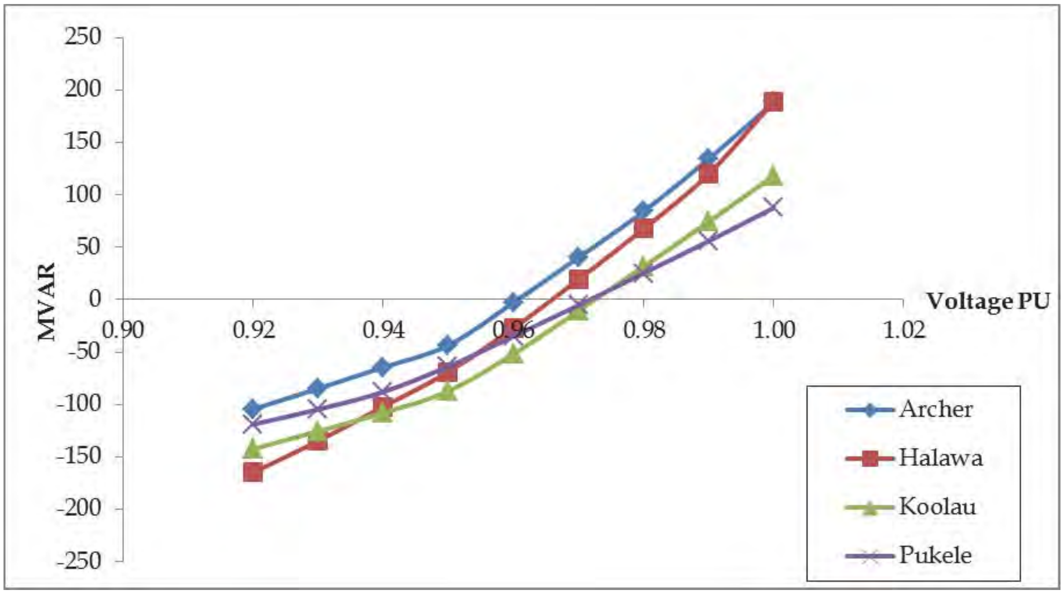

Figure O-53. QV Curves 2021

Figure O-53 shows the QV curves for the Archer, Halawa, Ko‘olau, and Pukele busses for the worst-case N-2 contingency event. The reactive power requirements are met with the additional MVARs from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	188	125	134	154	84	154	40	154	-3	135	-44	135	-65	135	-85	135	-105
120	Halawa	125	189	125	120	154	68	154	19	154	-27	154	-69	154	-102	154	-135	154	-165
150	Koolau	125	118	125	74	125	32	125	-11	125	-52	316	-87	316	-108	203	-126	203	-143
170	Pukele	125	88	125	56	125	25	125	-5	125	-35	125	-64	316	-88	316	-105	203	-119

Table O-32. Summary of Results 2021 QV Analysis

Table O-32 shows the results of the 2021 QV analysis. The unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

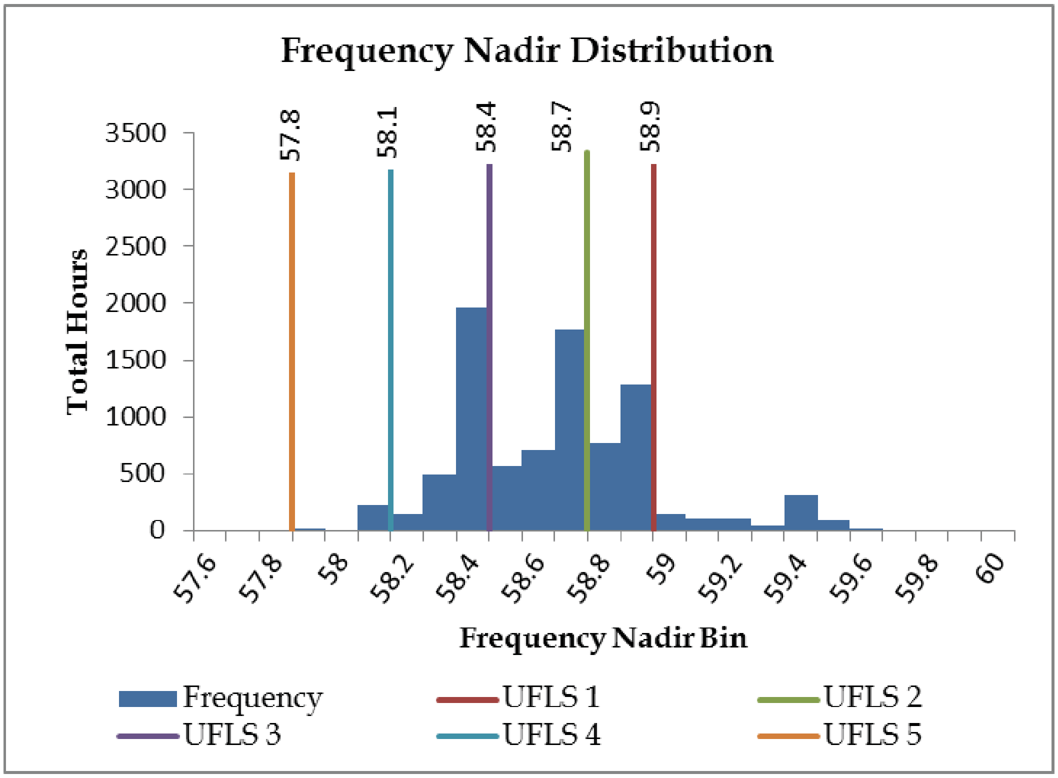

Figure O-54. Frequency Nadir Histogram 2021

Figure O-54 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1964 hours was 3:00 PM on Wednesday, November 3. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 220 hours was 10:00 AM on Friday, August 6. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

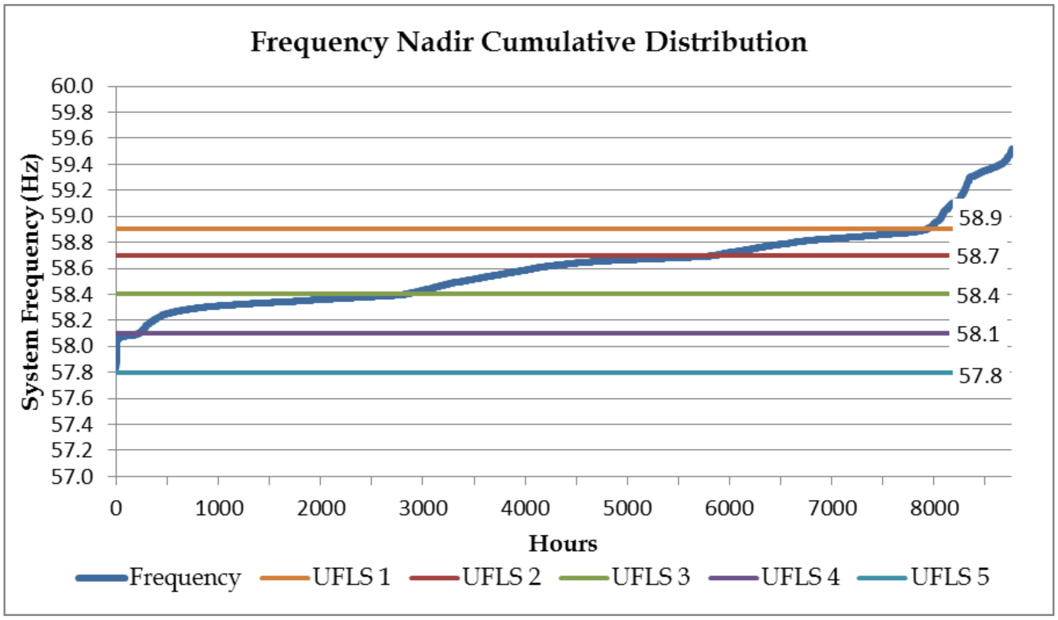

Figure O-55. Frequency Nadir Duration Curve 2021

Figure O-55 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for 7925 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Wed 11/3/21 Hour 15			Theme 5 - AES Trip Boundary Fri 8/6/21 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.5	4.5	16.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	27.6	12.4	17.6	32.3	7.7	22.3
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	26.4	108.2	5.4	21.4	113.2	0.4
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						33			41		
-Kahuku	30	0						5			14		
-Kawailoa	69	0						8			21		
-Na Pua Makani	24	0						12			2		
-CBRE Wind	10	0						2			1		
DG-PV	720	0						363			283		
Station PV	467	0						309			146		
Total Kinetic Energy								3735			3378		
Total Load								1152			917		
Total Thermal Generation								448			447		
Total Renewable Generation								704			470		
Total Generation								1152			917		
Excess Generation								0			0		
Total Up Regulation								238			153		
Total Down Regulation								237			260		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		36.7	59.3Hz Output		29.4
	60.5Hz Capacity		215.9					60.5Hz Output		107.9	60.5Hz Output		86.4

Table O-33. Unit Commitment and Dispatch 2021

Table O-33 shows the unit commitment and dispatch for the typical hour 11/3/21, 3:00 PM) and boundary hour (8/6/21, 10:00 AM).

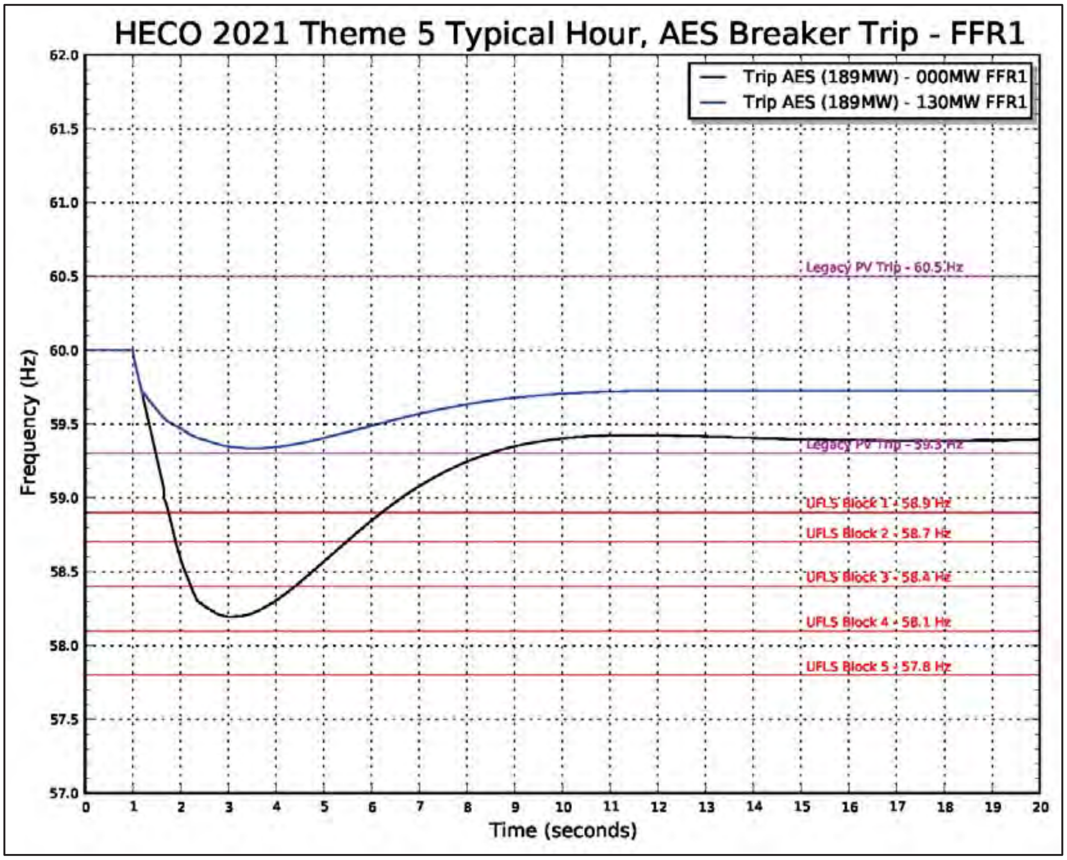

Figure O-56. Frequency Response Profile FFR1 Typical Hour

Figure O-56 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 36.7 MW. With no FFR, the frequency nadir is 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 130 MW.

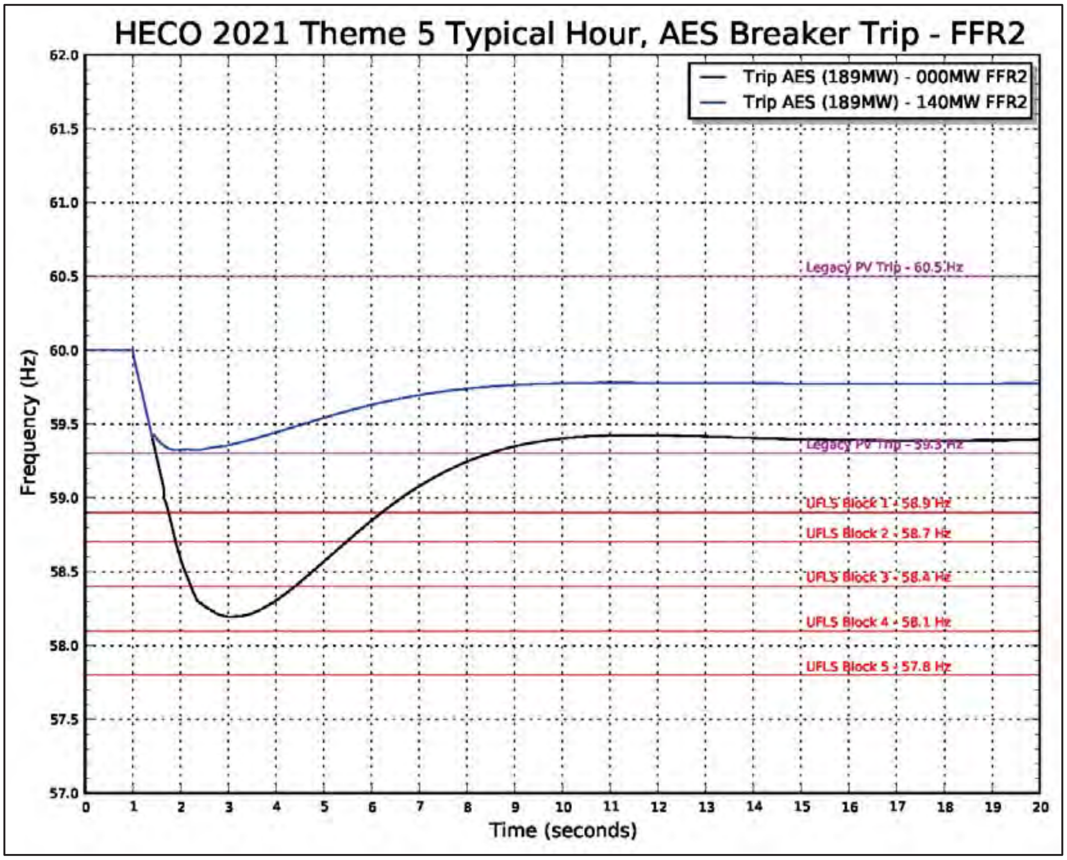

Figure O-57. Frequency Response Profile FFR2 Typical Hour

Figure O-57 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 140 MW.

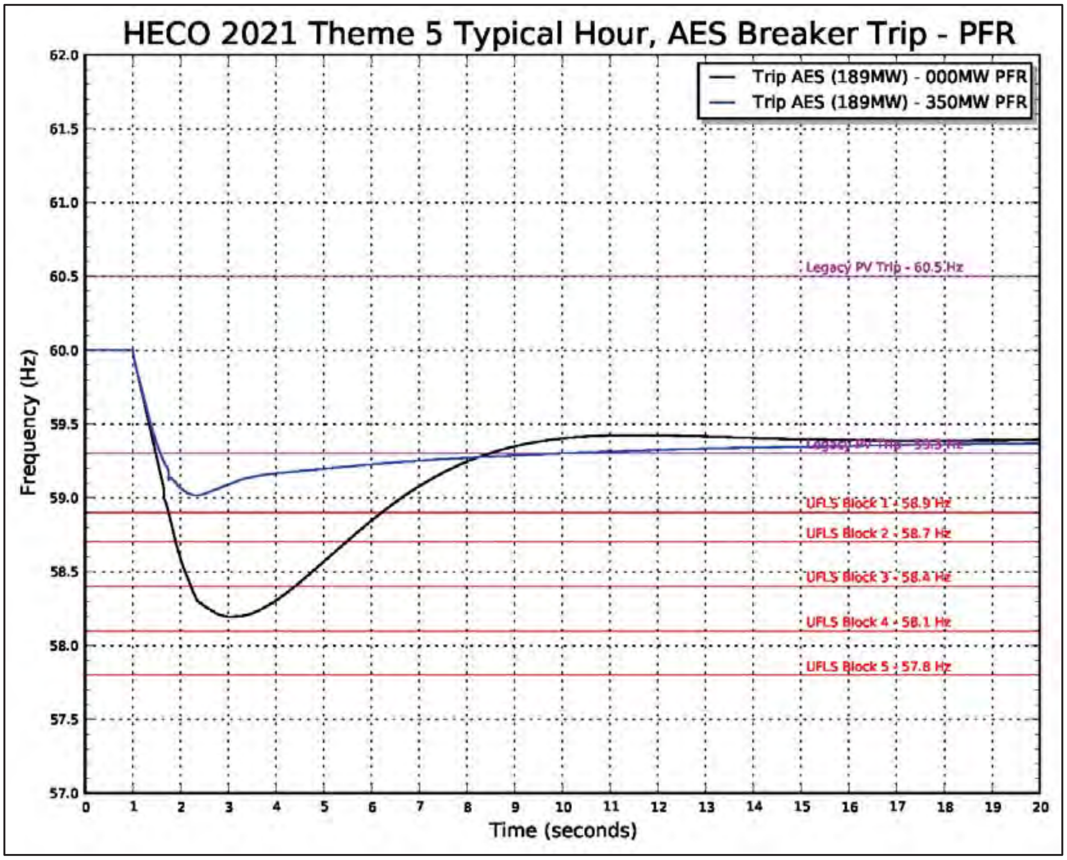

Figure O-58. Frequency Response Profile PFR Typical Hour

Figure O-58 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 350 MW. This is in addition to the 238 MW of upward regulation from thermal generation.

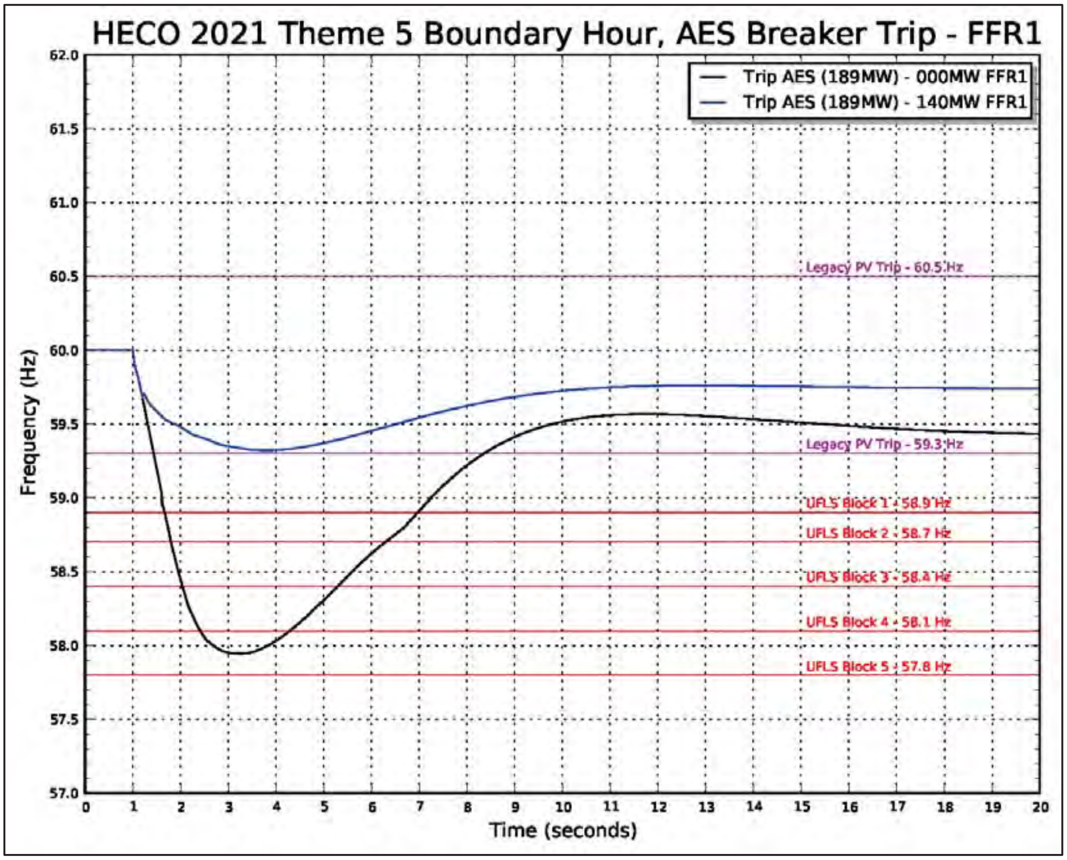

Figure O-59. Frequency Response Profile FFR1 Boundary Hour

Figure O-59 shows the frequency response profile for and AES trip at 189 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

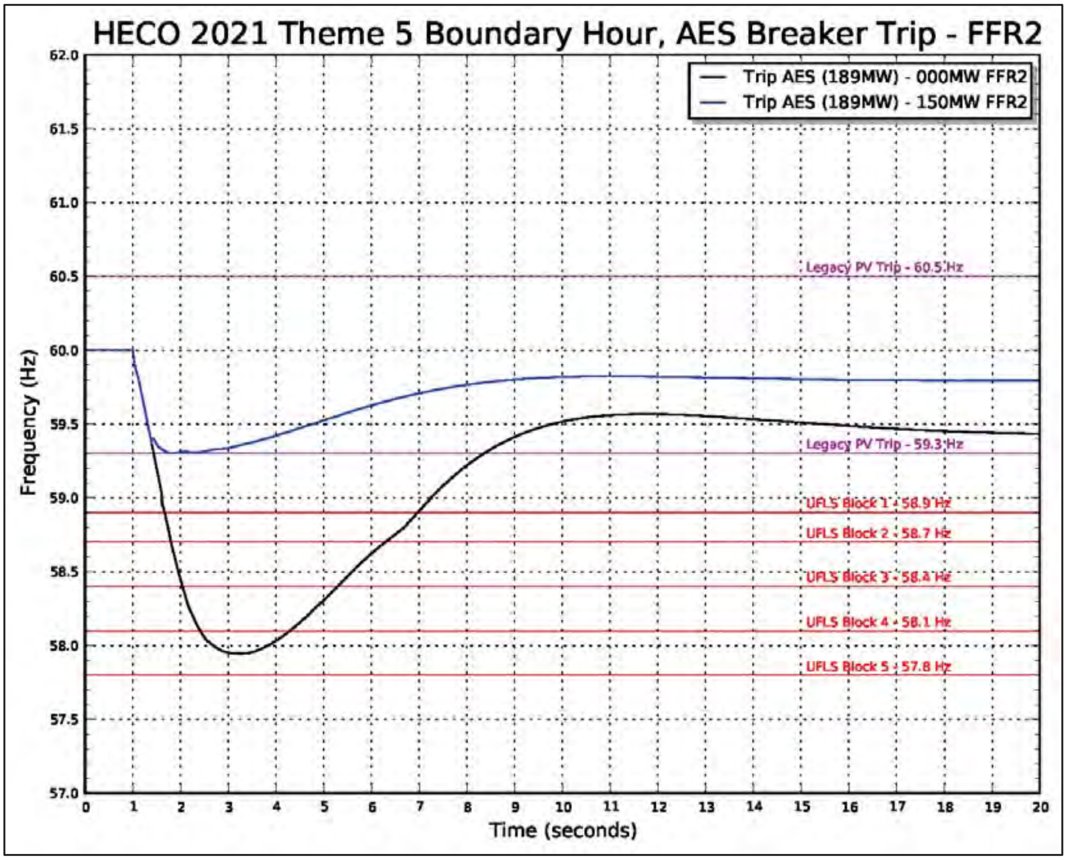

Figure O-60. Frequency Response Profile FFR2 Boundary Hour

Figure O-60 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

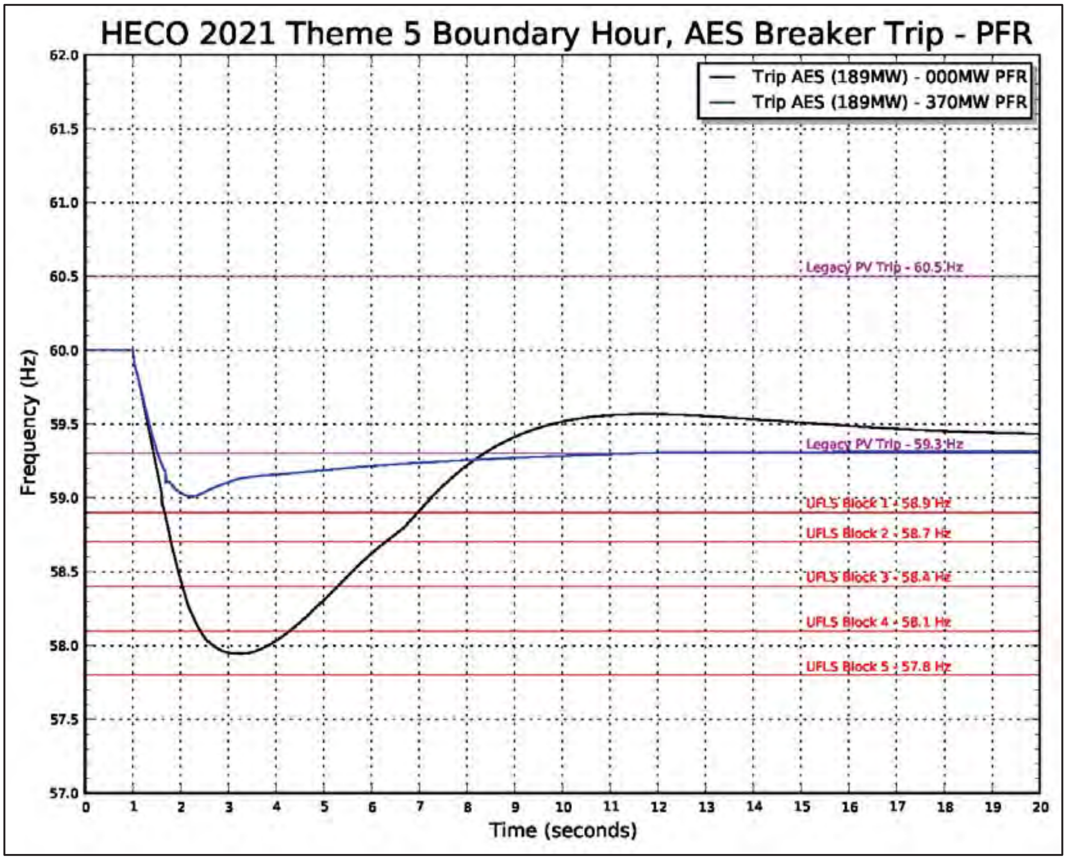

Figure O-61. Frequency Response Profile PFR Boundary Hour

Figure O-61 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 370 MW. This is in addition to the 153 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - Kahe 5 Trip Typical Wed 11/3/21 Hour 15			Theme 5 - K5 Trip Boundary Fri 8/6/21 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.5	4.5	16.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	81.0	108.0	18.0	76.0	113.0	13.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	27.6	12.4	17.6	32.3	7.7	22.3
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						33			41		
-Kahuku	30	0						5			14		
-Kawailoa	69	0						8			21		
-Na Pua Makani	24	0						12			2		
-CBRE Wind	10	0						2			1		
DG-PV	720	0						363			283		
Station PV	467	0						309			146		
Total Kinetic Energy								3735			3378		
Total Load								1152			917		
Total Thermal Generation								448			447		
Total Renewable Generation								704			470		
Total Generation								1152			918		
Excess Generation								0			0		
Total Up Regulation								238			153		
Total Down Regulation								237			260		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		36.7	59.3Hz Output		29.4
	60.5Hz Capacity			215.9				60.5Hz Output		107.9	60.5Hz Output		86.4

Table O-34. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-34 shows the unit commitment and dispatch for the typical hour (11/3/21, 3:00 PM) and boundary hour (8/6/21, 10:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

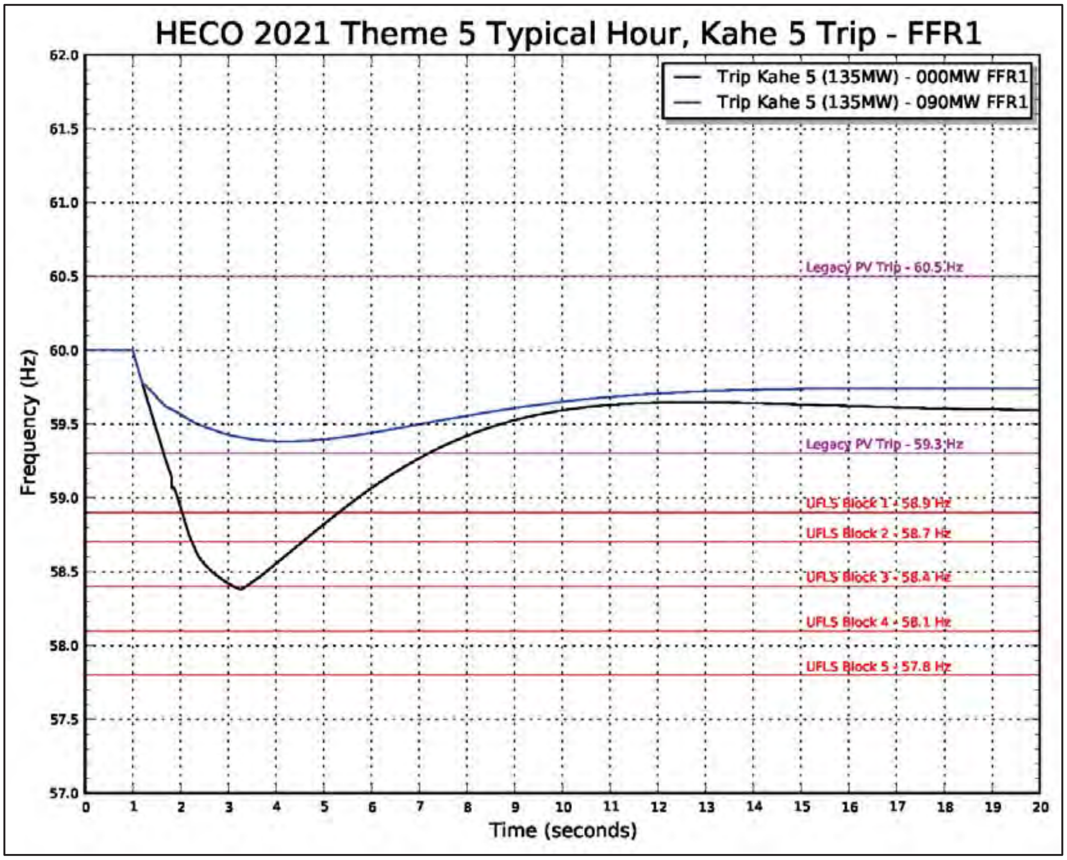

Figure O-62. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-62 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 36.7 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW.

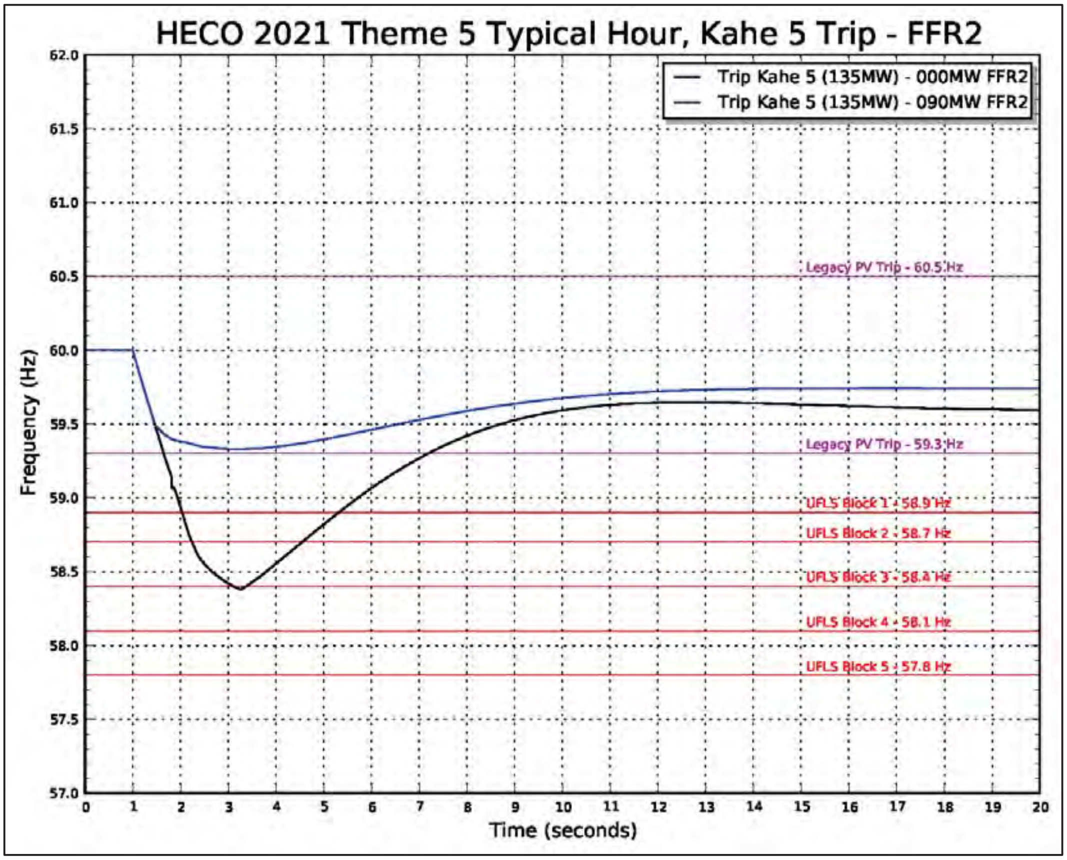

Figure O-63. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-63 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 90 MW.

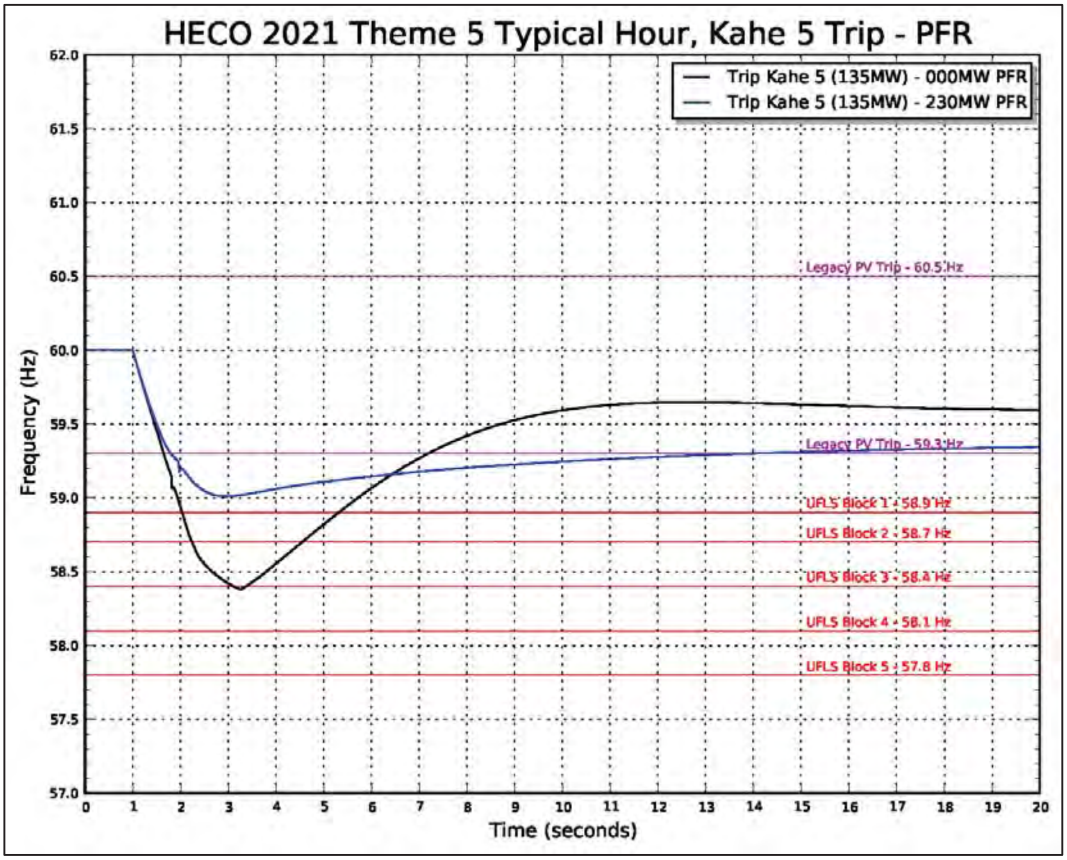

Figure O-64. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-64 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 238 MW of upward regulation from thermal generation.

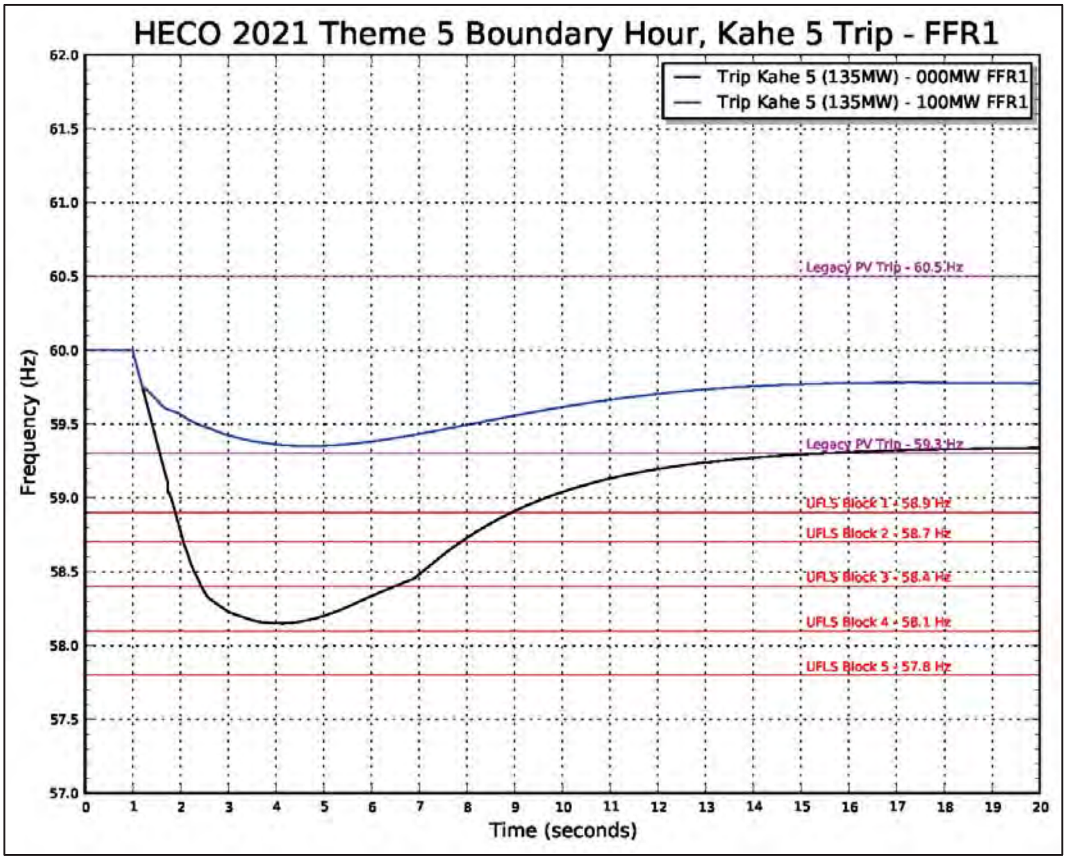

Figure O-65. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-65 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir breaches 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

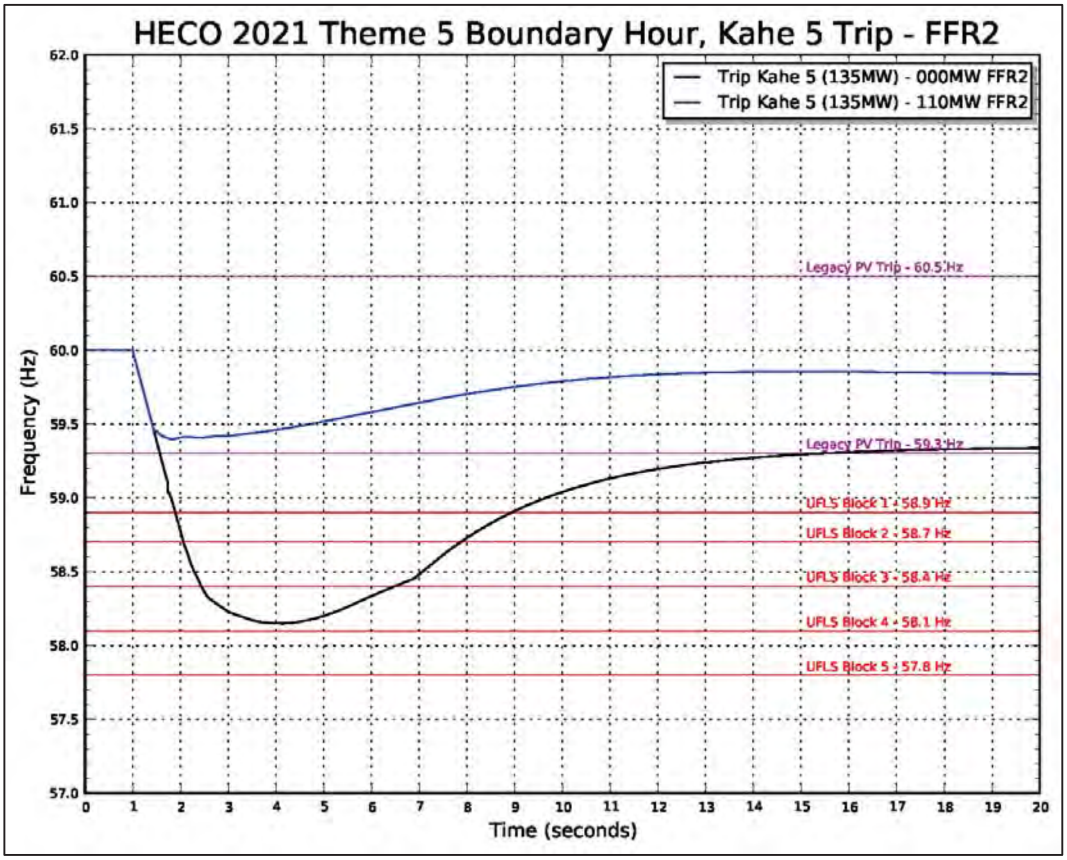

Figure O-66. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-66 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 110 MW.

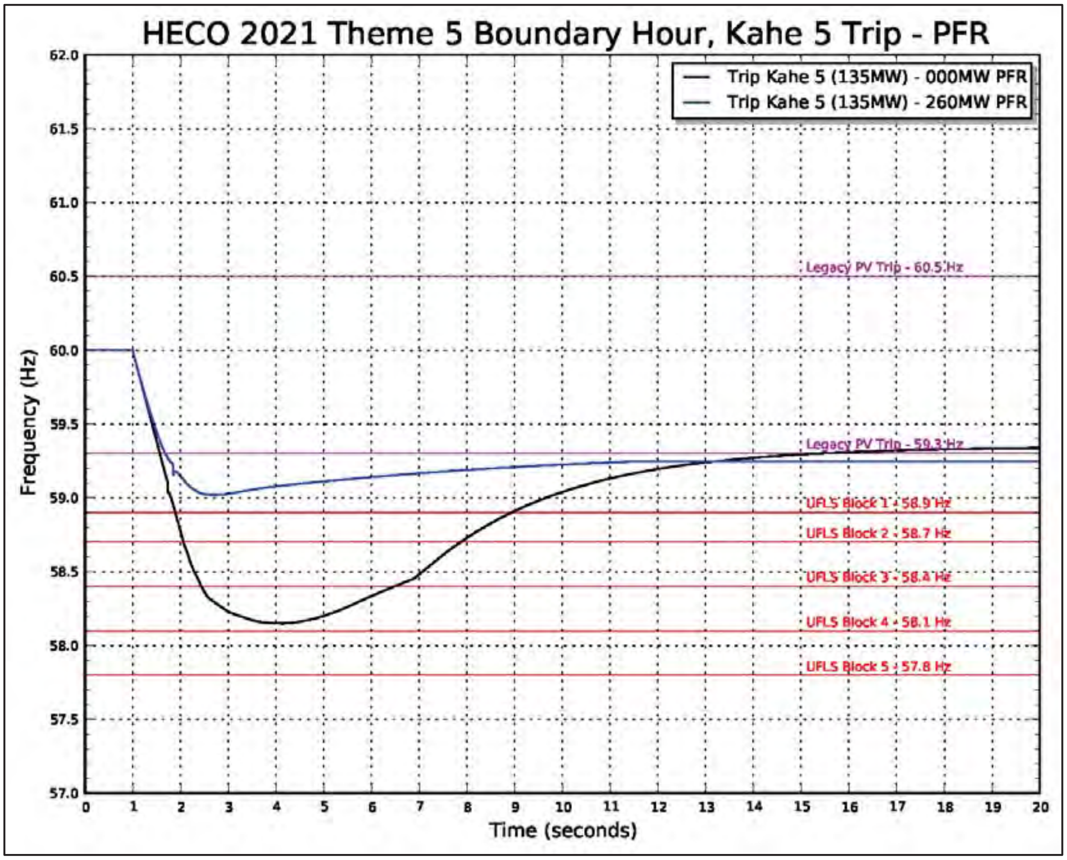

Figure O-67. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-67 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 153 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 7/18/21 Hour 14		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	26.6	19.4	1.6
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	27.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
JBPHH 1	16.8	6.7			0.99	21.8	22			
JBPHH 2	16.8	6.7			0.99	21.8	22			
JBPHH 3	16.8	6.7			0.99	21.8	22			
JBPHH 4	16.8	6.7			0.99	21.8	22			
JBPHH 5	16.8	6.7			0.99	21.8	22			
JBPHH 6	16.8	6.7			0.99	21.8	22			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						46		
-Kahuku	30	0						11		
-Kawailoa	69	0						21		
-Na Pua Makani	24	0						5		
-CBRE Wind	10	0						0		
DG-PV	720	0						575		
Station PV	467	0						218		
Total Kinetic Energy								2094		
Total Load								1003		
Total Thermal Generation								165		
Total Renewable Generation								839		
Total Generation								1003		
Excess Generation								0		
Total Up Regulation								217		
Total Down Regulation								28		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-35. Unit Commitment and Dispatch Fault Analysis

Table O-35 shows the unit commitment and dispatch for the fault analysis (7/18/2021, 2:00 PM).

Simulations for normally cleared faults were unstable for all 18 transmission circuits. The capacity of inverter-based generation has increased to the point where the margin of stability has been compromised.

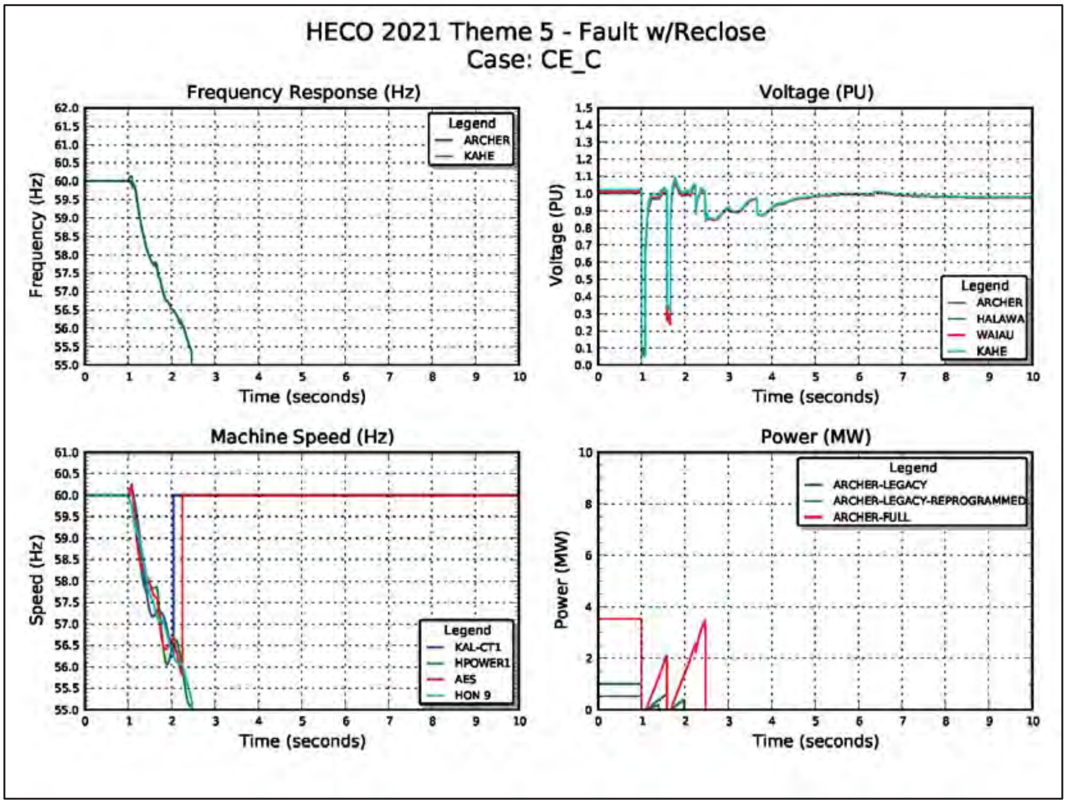

Figure O-68. System Performance Normally-Cleared Fault

Figure O-68 shows four plots that illustrates system performance for a fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation, essentially tripping 793 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS cannot prevent system frequency from breaching 57.0 Hz. The remaining synchronous units trip on under frequency protection, causing the system to collapse. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

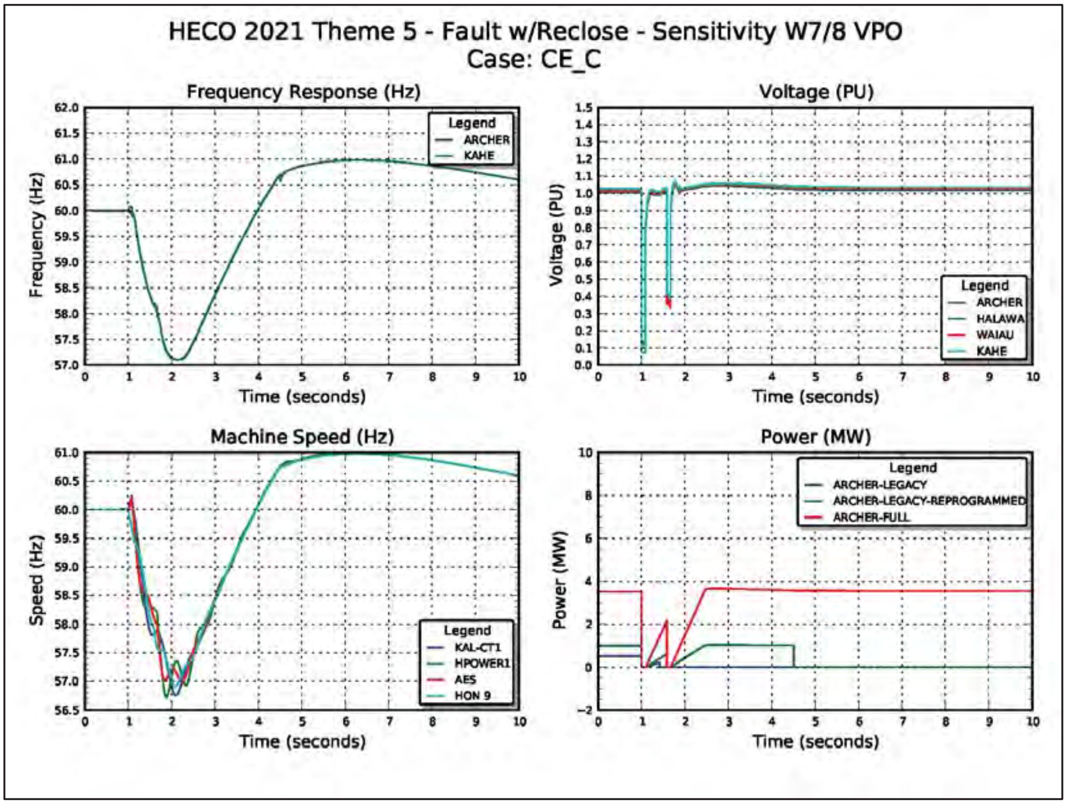

Figure O-69. System Performance Sensitivity Analysis VPO Units

Figure O-69 shows system performance with Waiau Units 7 and 8 operating in VPO. With additional synchronous units at Waiau, system voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting so generation from full ride-through inverters is restored. The aggregate response of synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.2 Hz.

The system does not meet the requirements of TPL-001. Non-exhaustive sensitivity analyses were performed to bring the system into compliance with TPL-001.

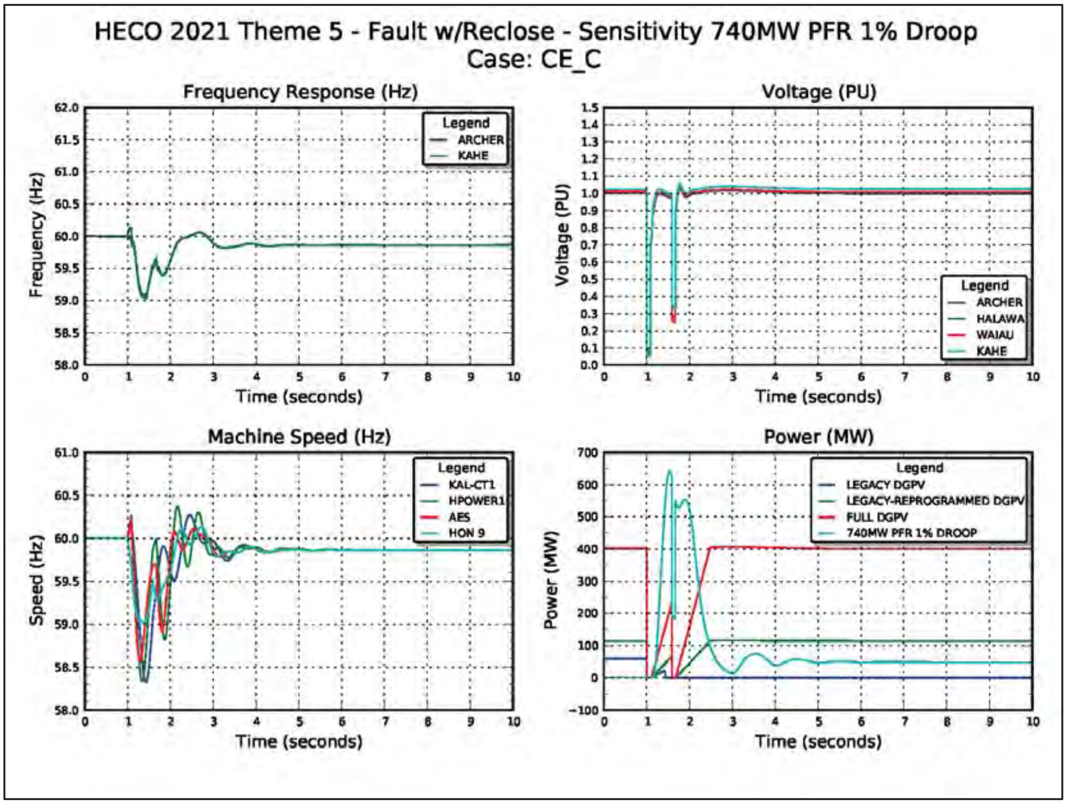

Figure O-70. System Performance Sensitivity Analysis 740 MW PFR

Figure O-70 shows system performance with the addition of the 740 MW of PFR at 1% droop response. For the purpose of this analysis, a 740 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 740 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

2021 138 kV Fault Analysis				
Circuit Outage	Reclose TD	Fault Hour Condition	Waiau 7/8 VPO Mitigation	740 MW PFR Mitigation
CEIP-Ewa Nui	30	Unstable	Stable	Stable
Halawa-Iwilei	30	Unstable	Stable	Stable
Halawa-Koolau	30	Unstable	Stable	Stable
Halawa-School	30	Unstable	Stable	Stable
Kahe-CEIP 1	30	Unstable	Stable	Stable
Kahe-CEIP 2	30	Unstable	Stable	Stable
Kalaeloa-Ewa Nui	30	Unstable	Stable	Stable
Kahe-Halawa 1	30	Unstable	Stable	Stable
Kahe-Halawa 2	30	Unstable	Stable	Stable
Kahe-Waiau	30	Unstable	Stable	Stable
Makalapa-Airport	30	Unstable	Stable	Stable
Waiau-Ewa Nui 1	30	Unstable	Stable	Stable
Waiau-Ewa Nui 2	30	Unstable	Stable	Stable
Waiau-Koolau 1	30	Unstable	Stable	Stable
Waiau-Koolau 2	30	Unstable	Stable	Stable
Waiau-Makalapa 1	30	Unstable	Stable	Stable
Waiau-Makalapa 2	30	Unstable	Stable	Stable
Waiau-Wahiawa	30	Unstable	Stable	Stable

Table O-36. Summary of Results Normally-Cleared Faults

Table O-36 shows the results of the normal clearing fault analysis. Simulations of a normally cleared fault resulted in system collapse for all transmission circuits. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency but multiple blocks of UFLS was also required.

The system requires 740 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2022

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

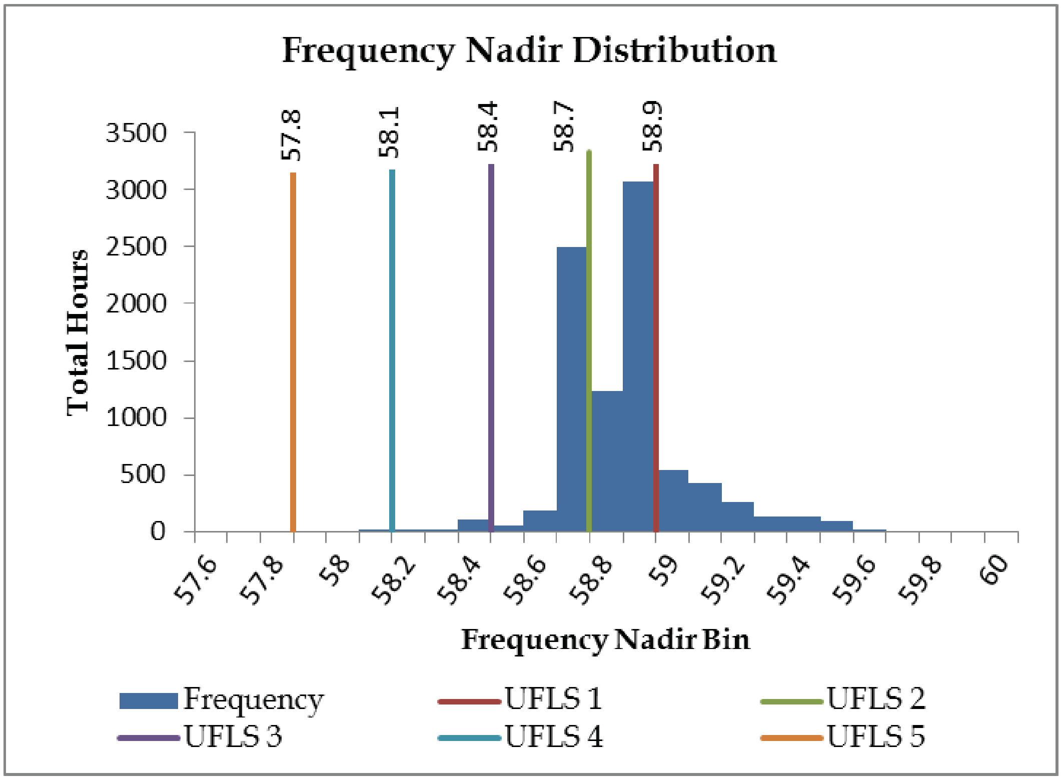

Figure O-71. Frequency Nadir Histogram 2022

Figure O-71 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1155 hours was 5:00 PM on Tuesday, August 16. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 12 hours was 10:00 AM on Friday, August 5. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

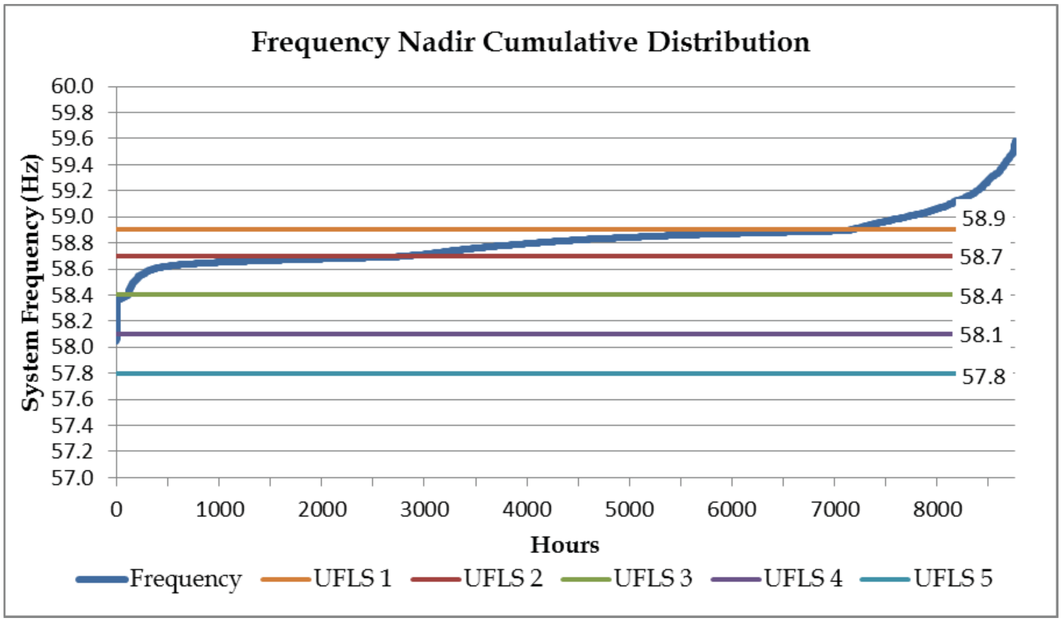

Figure O-72. Frequency Nadir Duration Curve 2022

Figure O-72 shows the frequency nadir duration curve for 2022. The system is at risk of UFLS for 7484 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Tue 8/16/22 Hour 17			Theme 5 - AES Trip Boundary Fri 8/5/22 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.5	0.5	20.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	20.7	1.8	10.7	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	58.5	25.5	29.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.0	1.0	29.0	27.9	12.1	17.9
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	58.5	25.5	29.5
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	29.3	105.3	8.3			
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						54			45		
-Kahuku	30	0						10			14		
-Kawailoa	69	0						16			21		
-Na Pua Makani	24	0						16			2		
-CBRE Wind	10	0						3			2		
DG-PV	740	0						294			297		
Station PV	547	0						317			163		
Total Kinetic Energy									3378			2686	
Total Load									1151			909	
Total Thermal Generation									487			402	
Total Renewable Generation									664			506	
Total Generation									1151			909	
Excess Generation									0			0	
Total Up Regulation									113			63	
Total Down Regulation									300			236	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		29.4	59.3Hz Output		29.4
	60.5Hz Capacity		215.9					60.5Hz Output		86.4	60.5Hz Output		86.4

Table O-37. Unit Commitment and Dispatch 2022

Table O-37 shows the unit commitment and dispatch for the typical hour (8/16/22, 5:00 PM) and boundary hour (8/5/22, 10:00 AM).

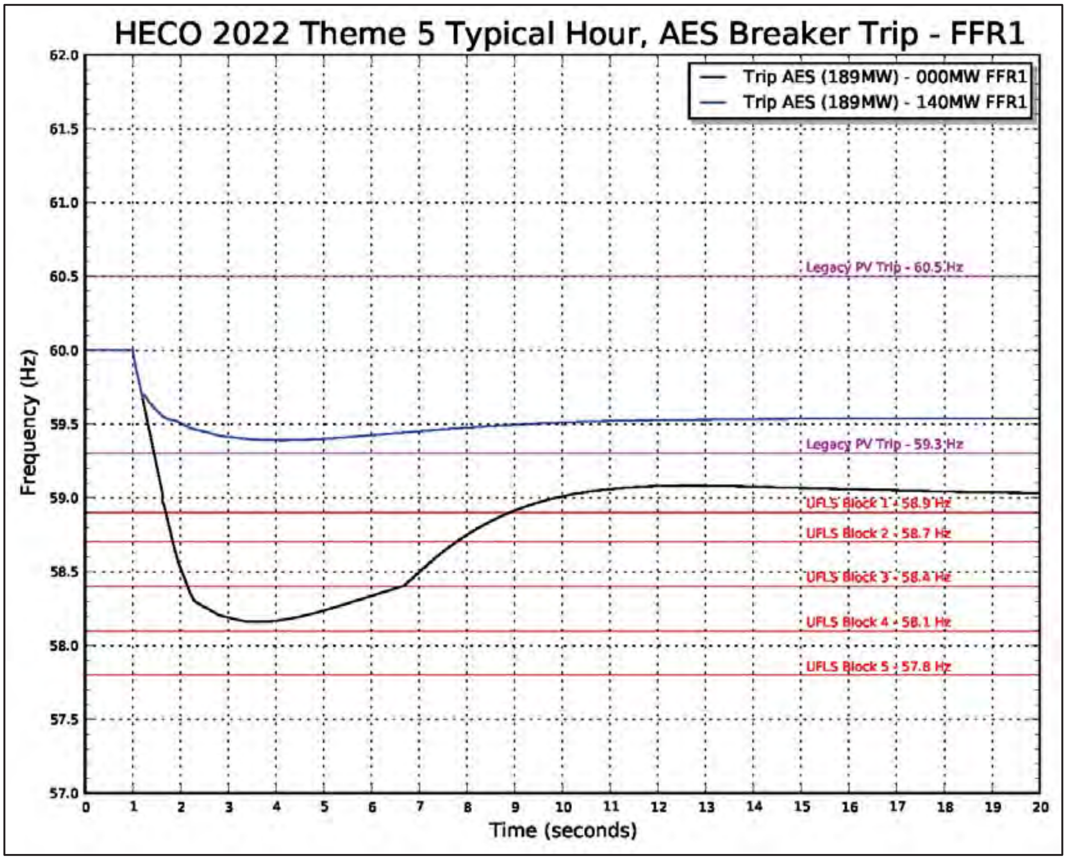

Figure O-73. Frequency Response Profile FFR1 Typical Hour

Figure O-73 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

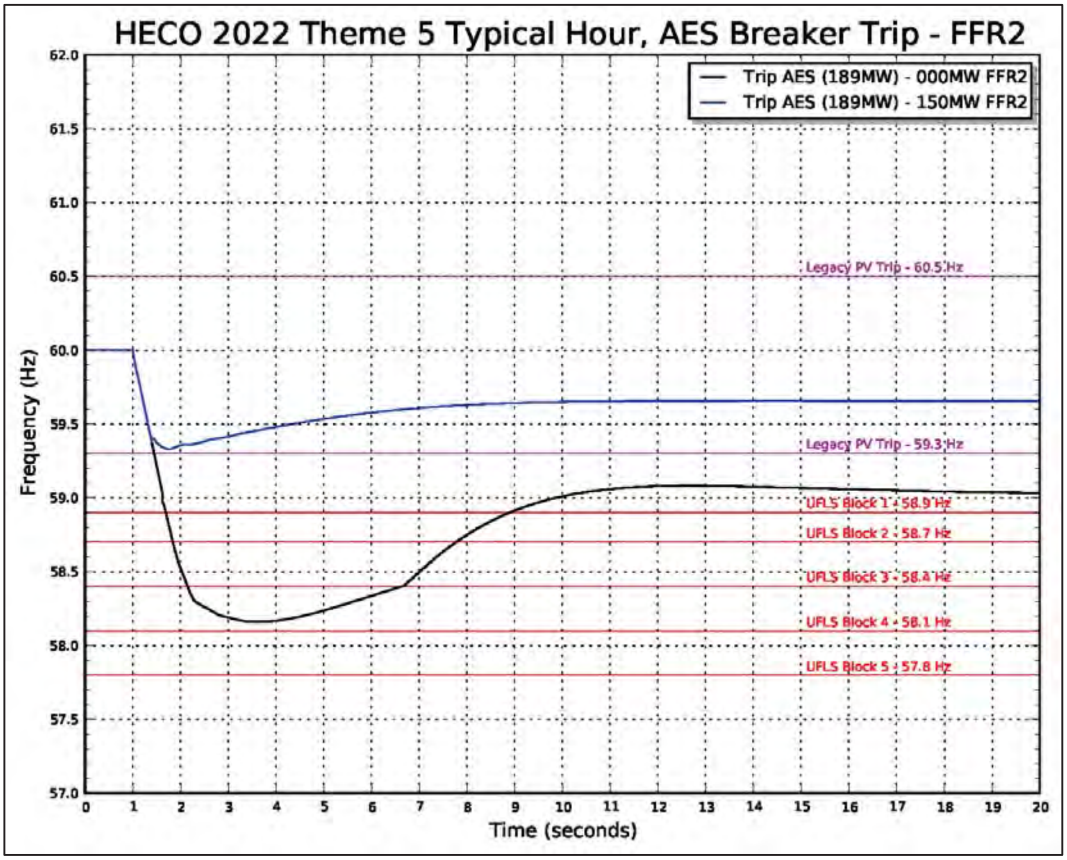

Figure O-74. Frequency Response Profile FFR2 Typical Hour

Figure O-74 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

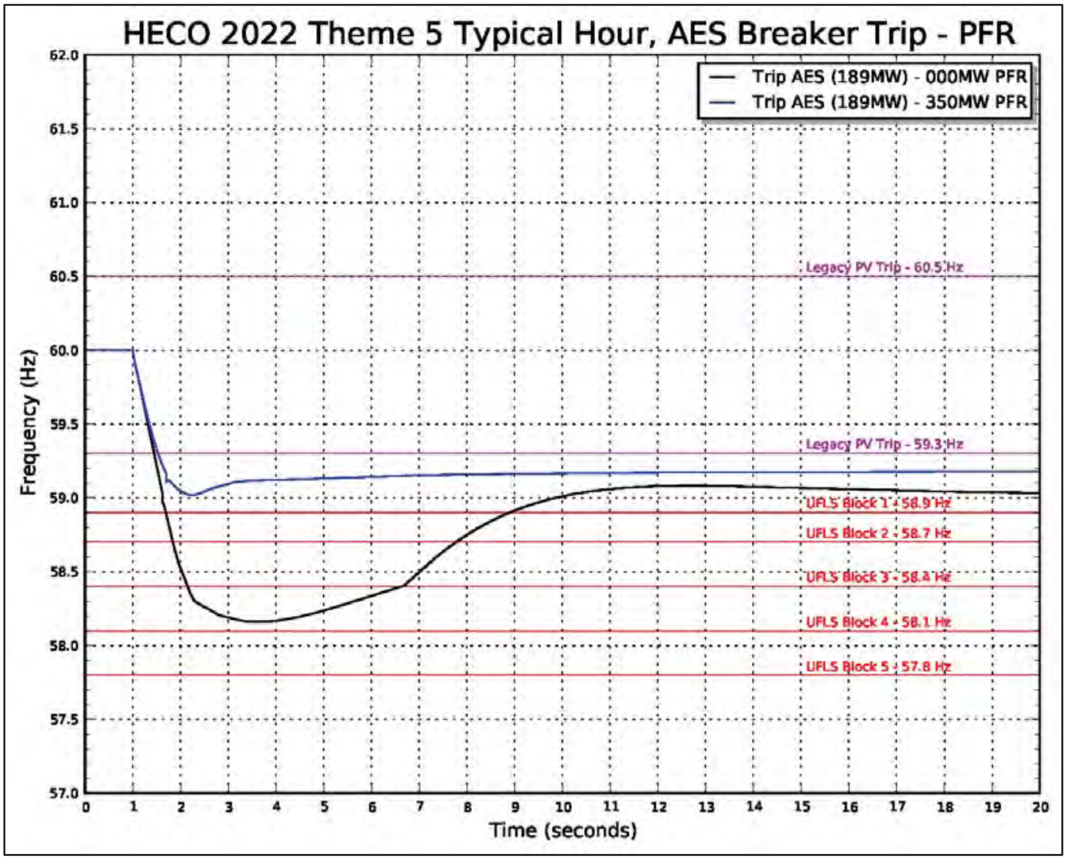

Figure O-75. Frequency Response Profile PFR Typical Hour

Figure O-75 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 350 MW. This is in addition to the 113 MW of upward regulation from thermal generation.

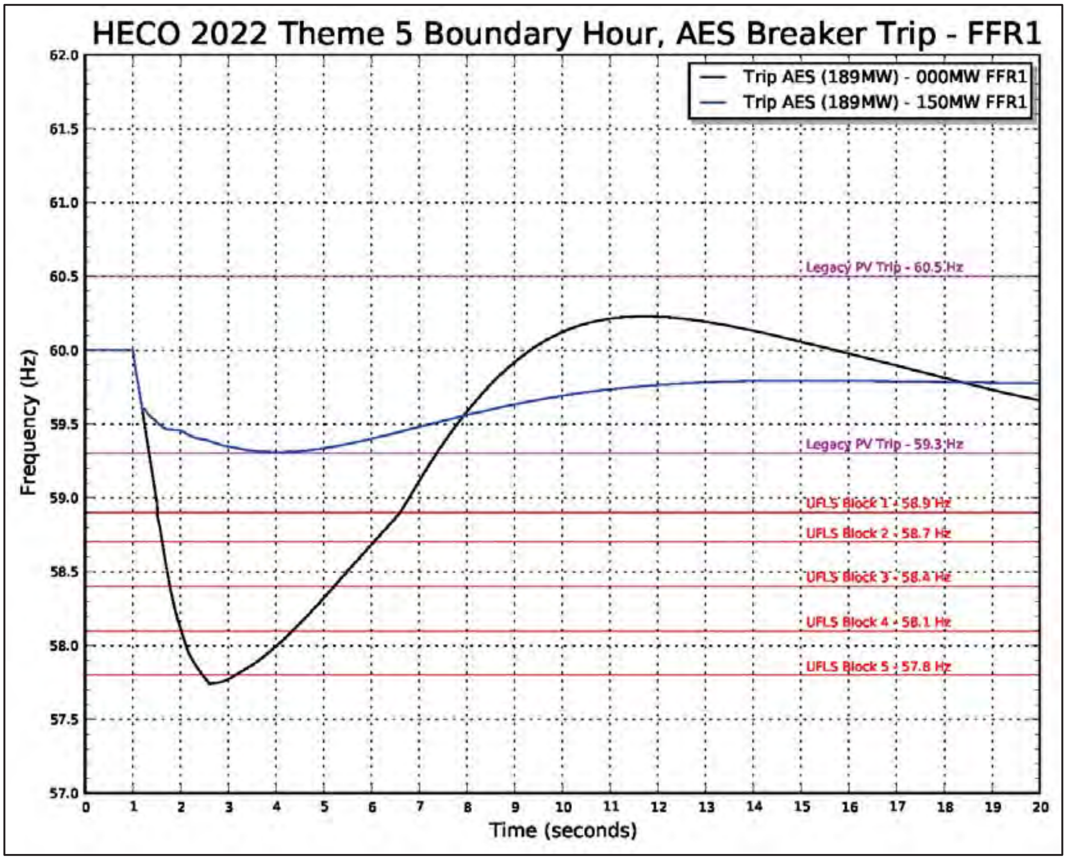

Figure O-76. Frequency Response Profile FFR1 Boundary Hour

Figure O-76 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 2686 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 57.7 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

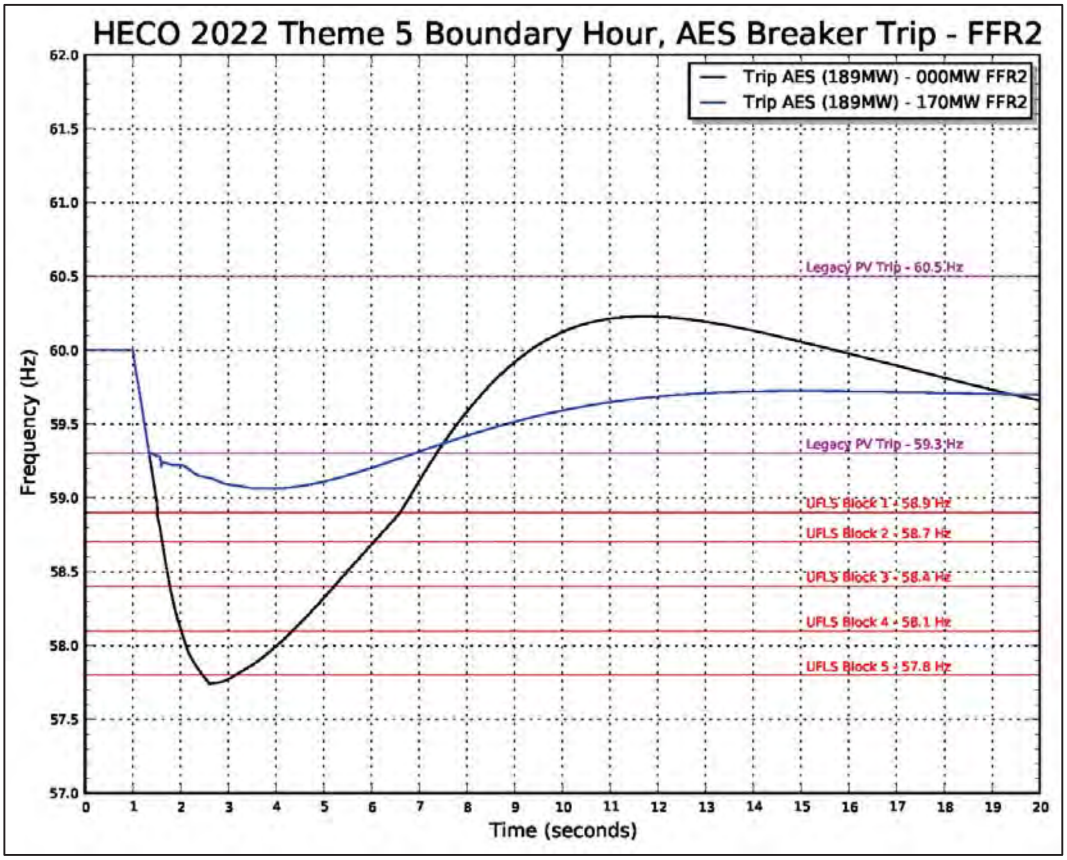

Figure O-77. Frequency Response Profile FFR2 Boundary Hour

Figure O-77 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

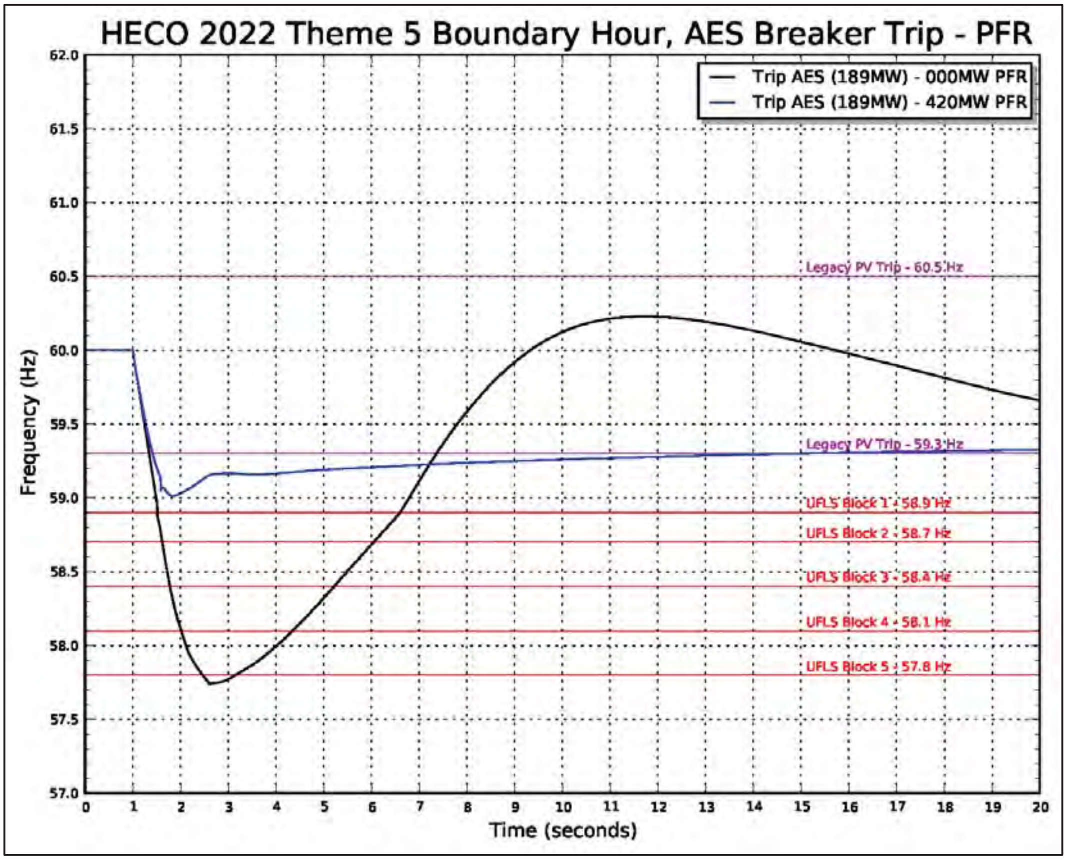

Figure O-78. Frequency Response Profile PFR Boundary Hour

Figure O-78 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 420 MW. This is in addition to the 63 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Tue 8/16/22 Hour 17			Theme 5 - K5 Trip Boundary Fri 8/5/22 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.5	0.5	20.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	20.7	1.8	10.7	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	84.0	105.0	21.0	95.0	94.0	32.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.0	1.0	29.0	20.0	0.0	10.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						54			45		
-Kahuku	30	0						10			14		
-Kawailoa	69	0						16			21		
-Na Pua Makani	24	0						16			2		
-CBRE Wind	10	0						3			2		
DG-PV	740	0						294			297		
Station PV	547	0						317			163		
Total Kinetic Energy								3378			2787		
Total Load								1151			909		
Total Thermal Generation								487			402		
Total Renewable Generation								664			506		
Total Generation								1152			908		
Excess Generation								0			0		
Total Up Regulation								113			94		
Total Down Regulation								300			244		
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			73.5 215.9				59.3Hz Output 60.5Hz Output		29.4 86.4	59.3Hz Output 60.5Hz Output		29.4 86.4

Table O-38. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-38 shows the unit commitment and dispatch for the typical hour (5/26/22, 3:00 PM) and boundary hour (7/10/2022, 9:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

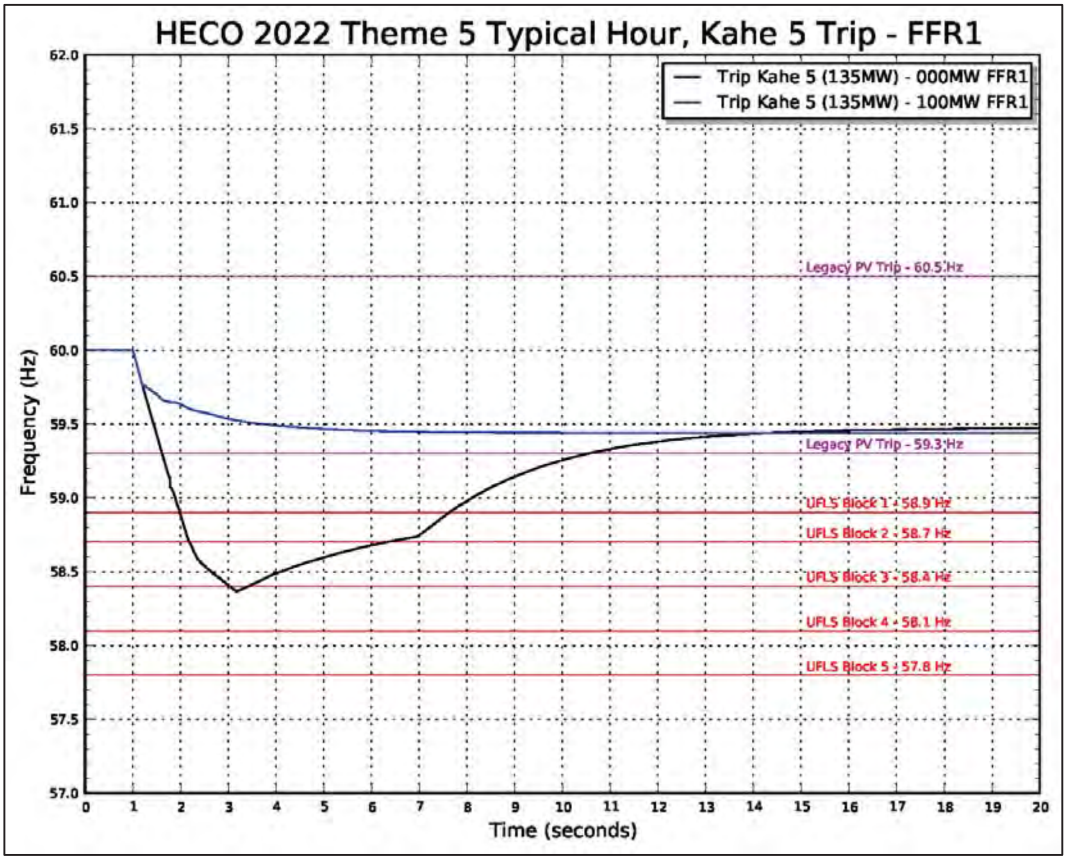

Figure O-79. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-79 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

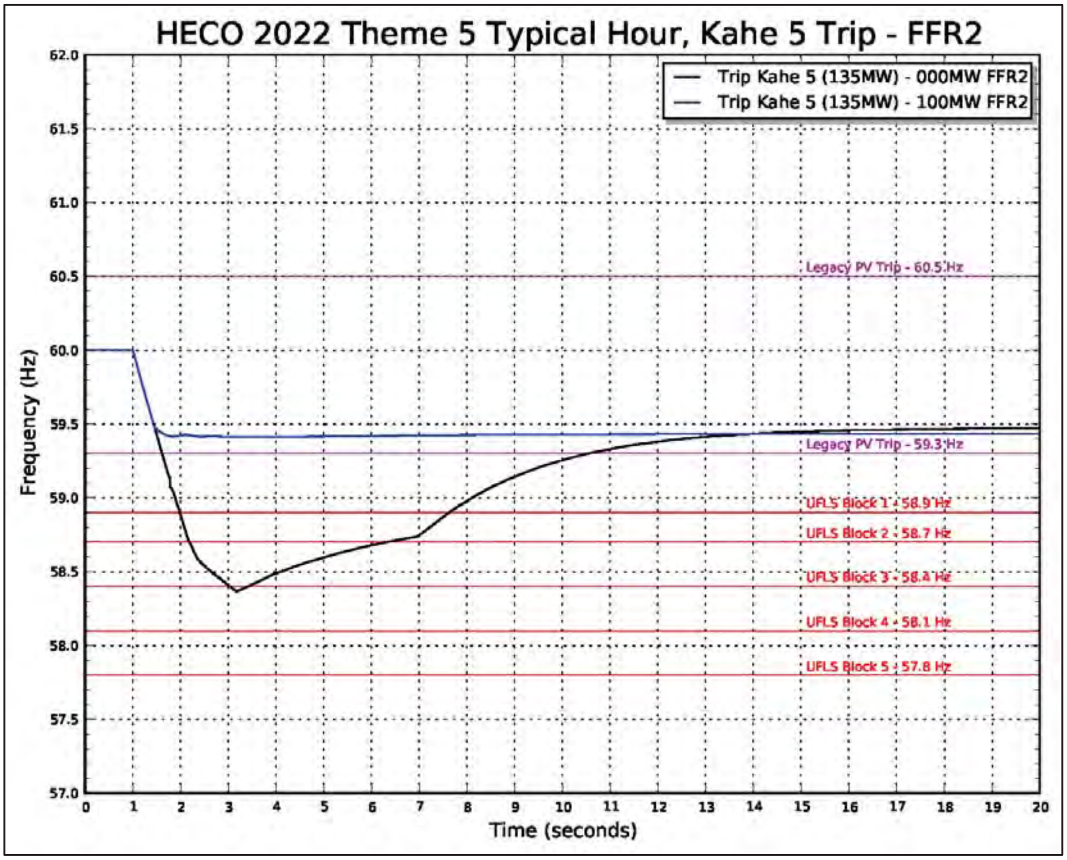

Figure O-80. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-80 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 100 MW.

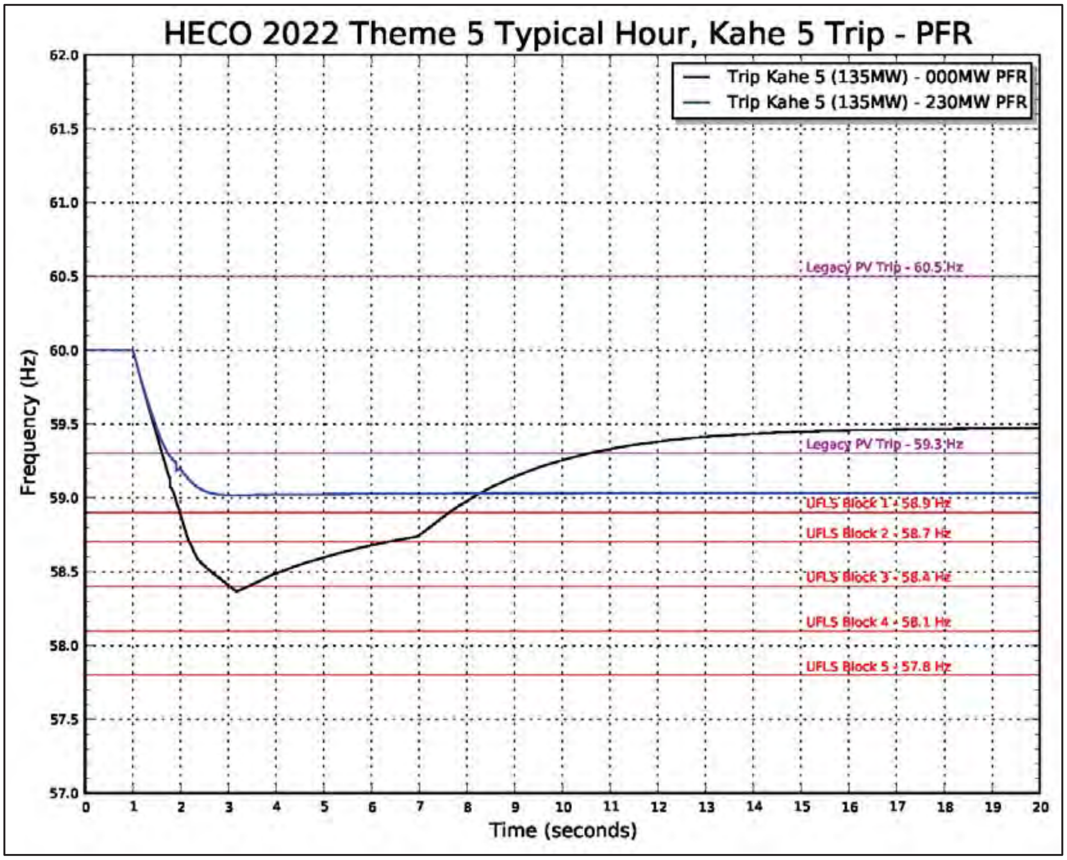

Figure O-81. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-81 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 113 MW of upward regulation in from thermal generation.

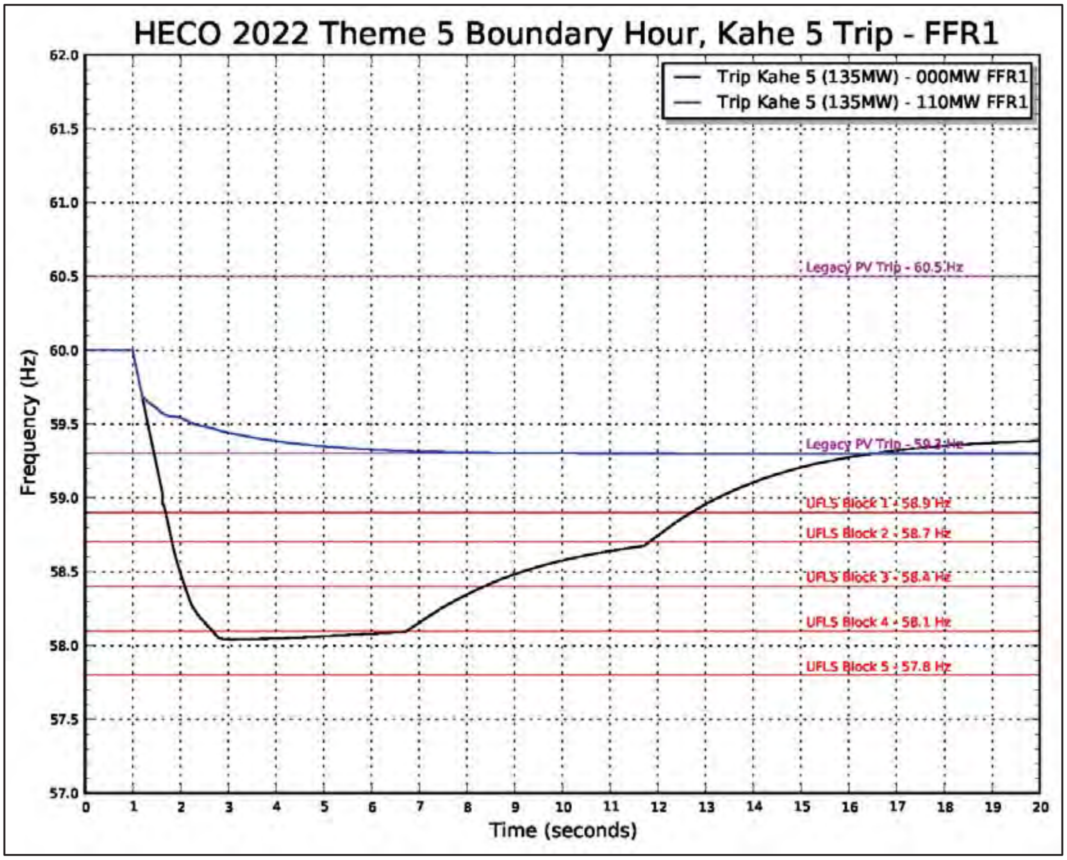

Figure O-82. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-82 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 2787 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

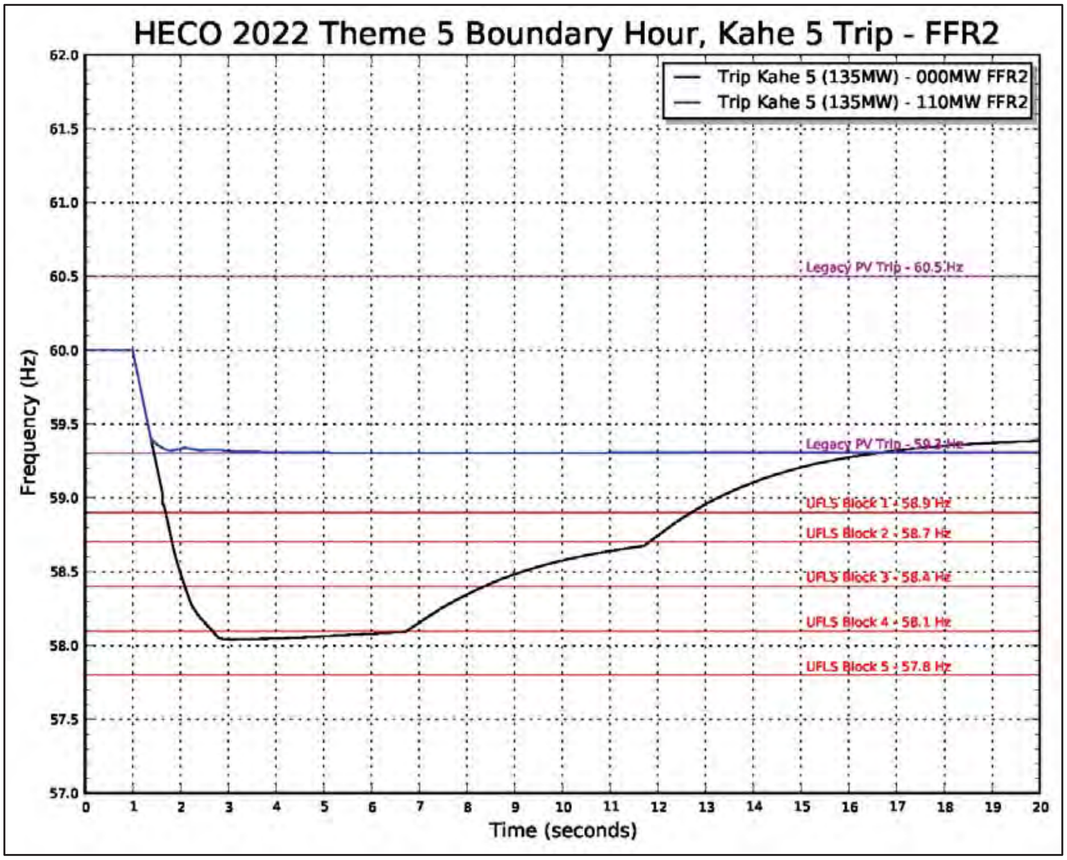

Figure O-83. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-83 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 110 MW.

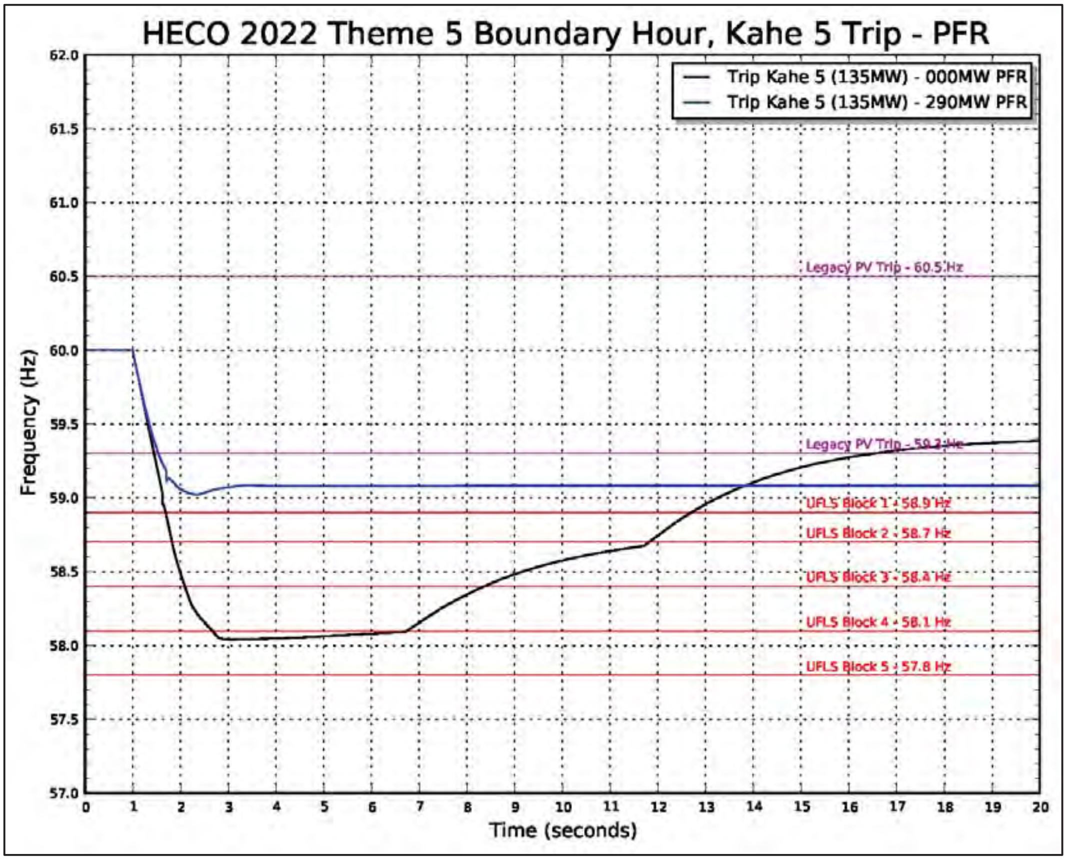

Figure O-84. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-84 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 63 MW of upward regulation from thermal generation.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

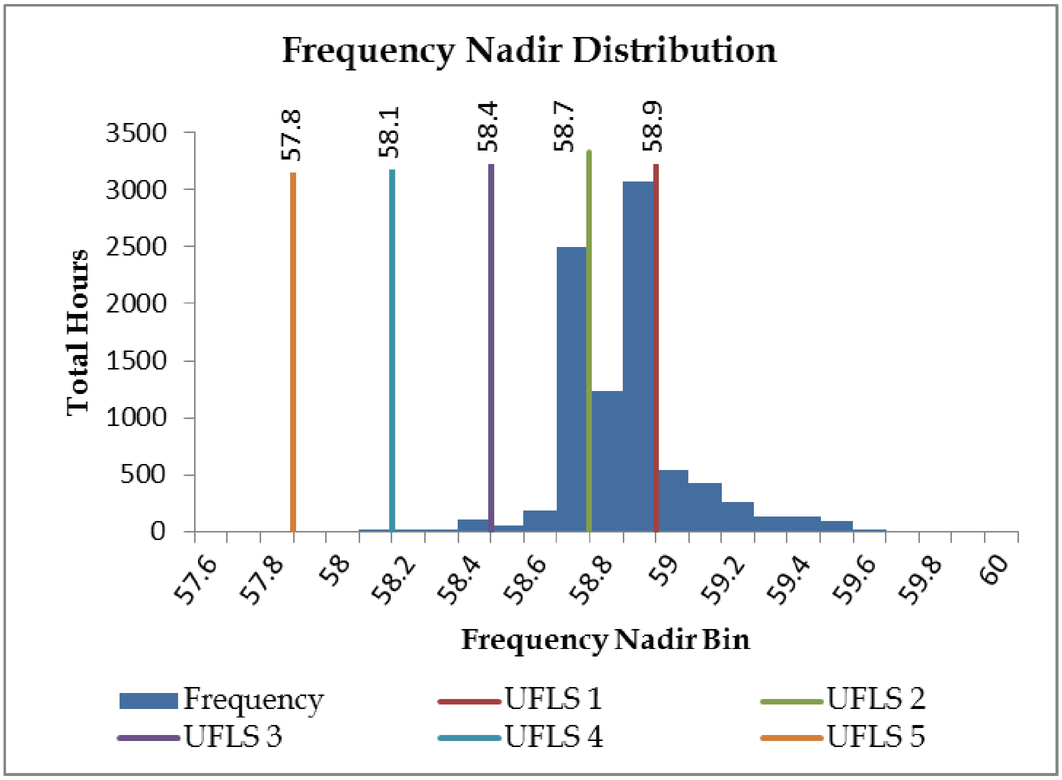

Figure O-85. Frequency Nadir Histogram 2023

Figure O-85 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2494 hours was 9:00 PM on Friday, July 14. The frequency nadir range for the typical hour is 58.6- 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 1 hour was 10:00 AM on Sunday, January 22. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires four blocks of UFLS to stabilize system frequency.

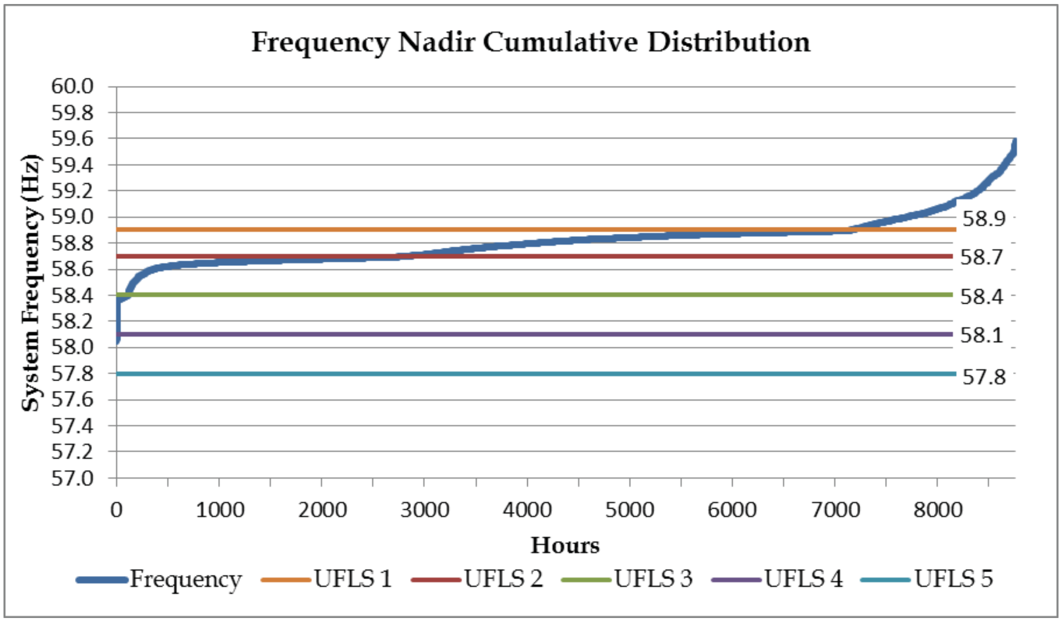

Figure O-86. Frequency Nadir Duration Curve 2023

Figure O-86 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 7159 hours of the year.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Fri 7/14/23 Hour 9			Theme 5 - K5 Trip Boundary Sun 1/22/23 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	41.5	4.5	16.5
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0	22.5	0.0	12.5
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0			
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	63.1	19.1	39.3			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357				71.8	14.4	48.1
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	80.7	4.6	57.1			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	127.7	6.9	106.7
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						70			19		
-Kahuku	30	0						13			5		
-Kawailoa	69	0						24			6		
-Na Pua Makani	24	0						21			0		
-CBRE Wind	10	0						3			2		
DG-PV	755	0						160			288		
Station PV	607	0						212			335		
Total Kinetic Energy								3546			1651		
Total Load								973			906		
Total Thermal Generation								532			263		
Total Renewable Generation								442			642		
Total Generation								973			906		
Excess Generation								0			0		
Total Up Regulation								47			26		
Total Down Regulation								361			184		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		14.7	59.3Hz Output		29.4
	60.5Hz Capacity			215.9				60.5Hz Output		43.2	60.5Hz Output		86.4

Table O-39. Unit Commitment and Dispatch 2023

Table O-39 shows the unit commitment and dispatch for the typical hour (7/14/23, 9:00 AM) and boundary hour (1/22/23, 10:00 AM).

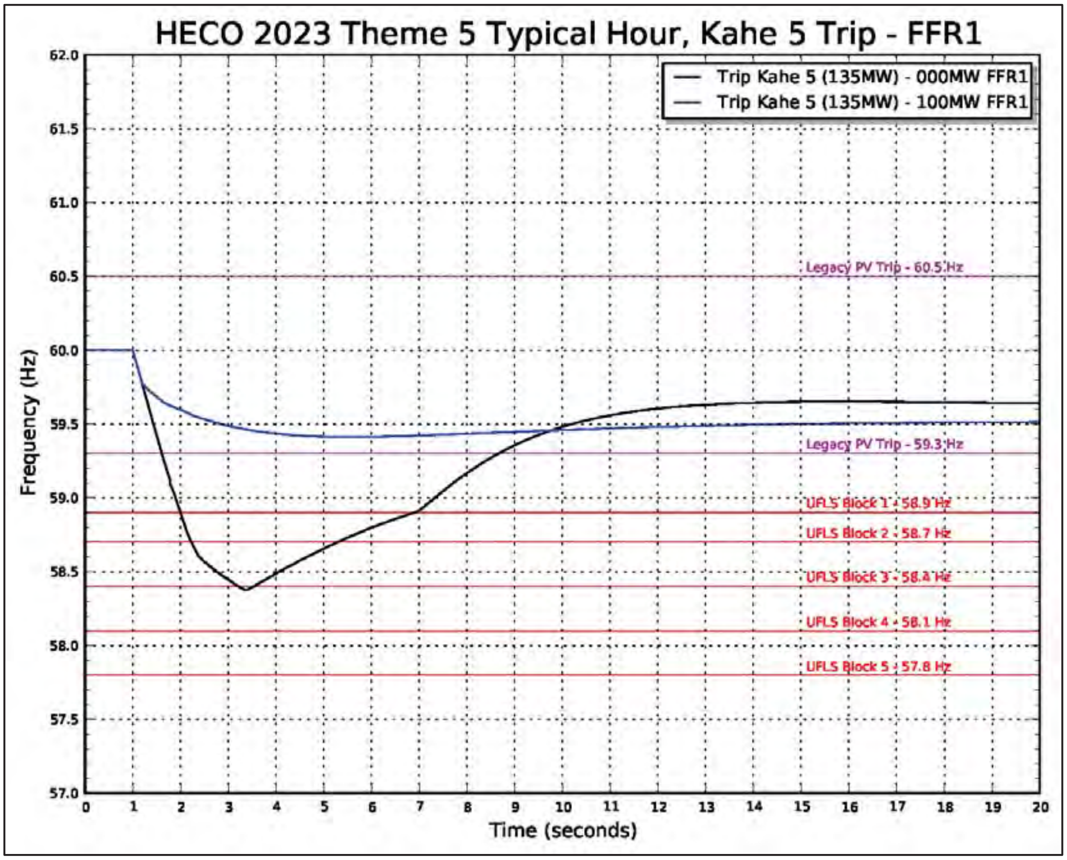

Figure O-87. Frequency Response Profile FFR1 Typical Hour

Figure O-87 shows the frequency response profile for a Kahe 5 trip for a typical hour. System kinetic energy is 3546 MW-sec and the capacity of legacy PV that will disconnect from the system is 14.7 MW. With no FFR, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

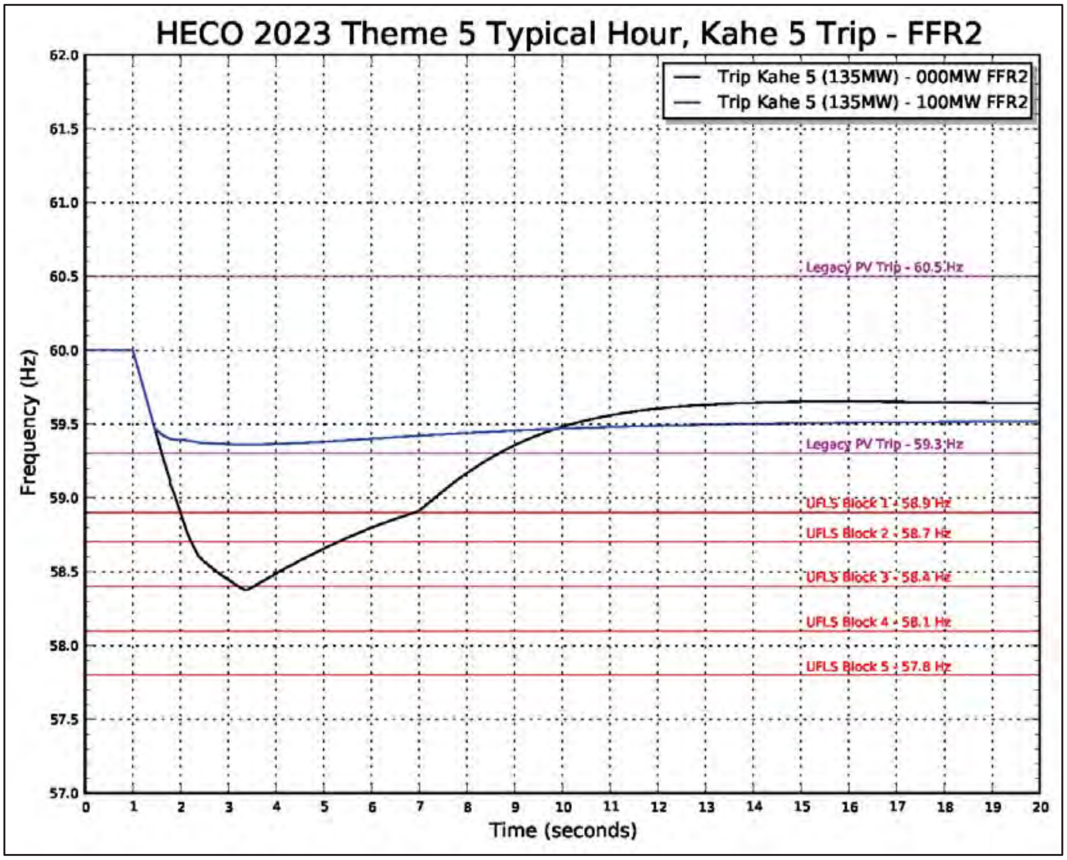

Figure O-88. Frequency Response Profile FFR2 Typical Hour

Figure O-88 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

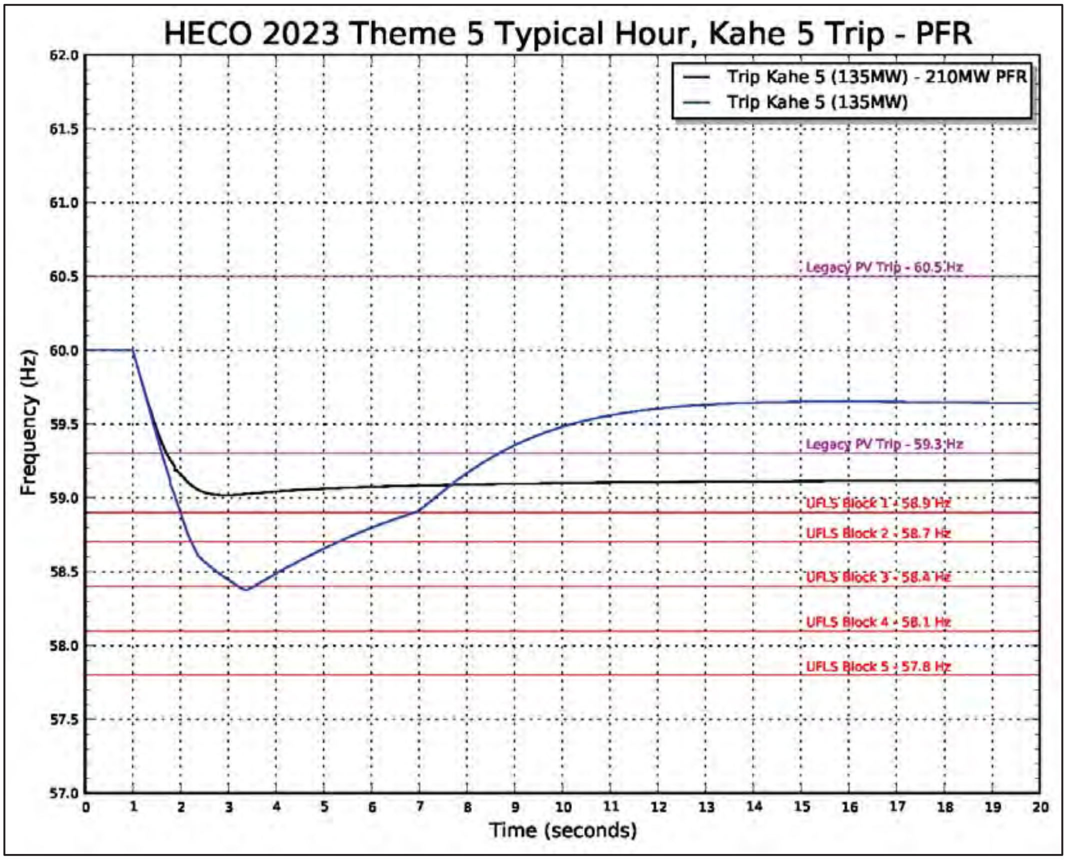

Figure O-89. Frequency Response Profile PFR Typical Hour

Figure O-89 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 210 MW. This is in addition to the 47 MW of upward regulation from thermal generation.

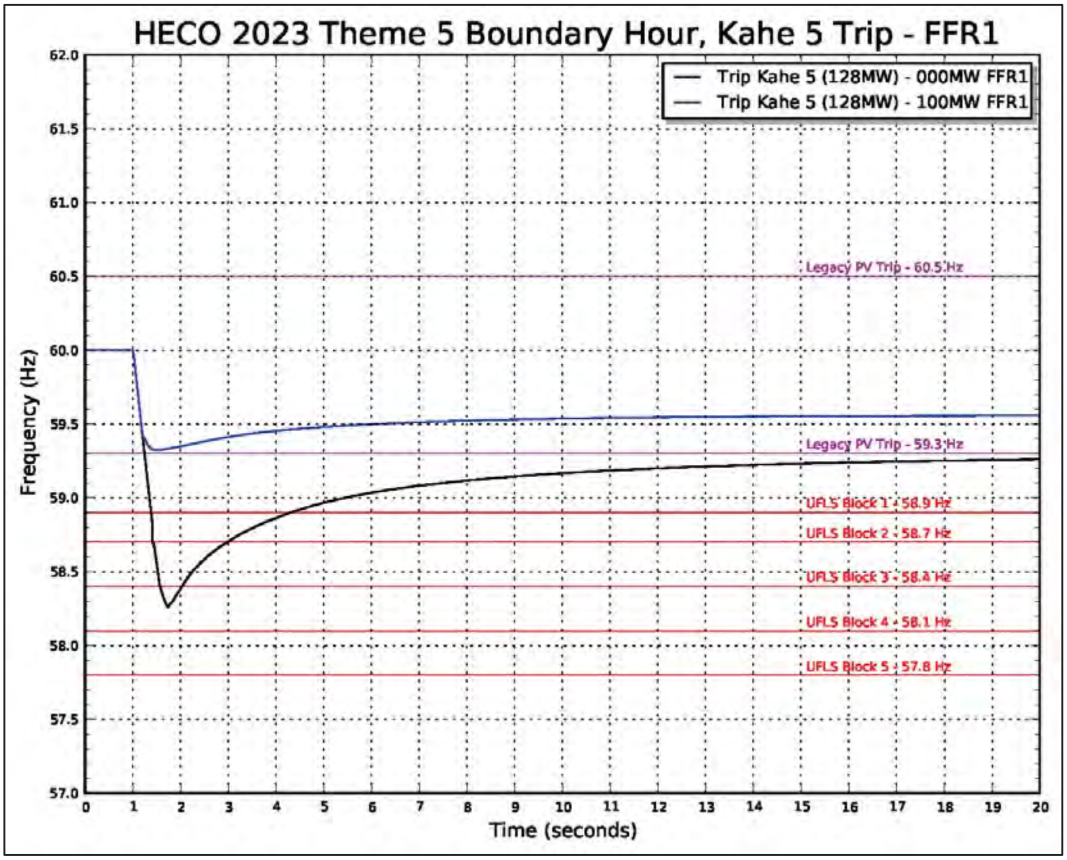

Figure O-90. Frequency Response Profile FFR1 Boundary Hour

Figure O-90 shows the frequency response profile for a Kahe 5 trip for a boundary hour. System kinetic energy is 1651 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

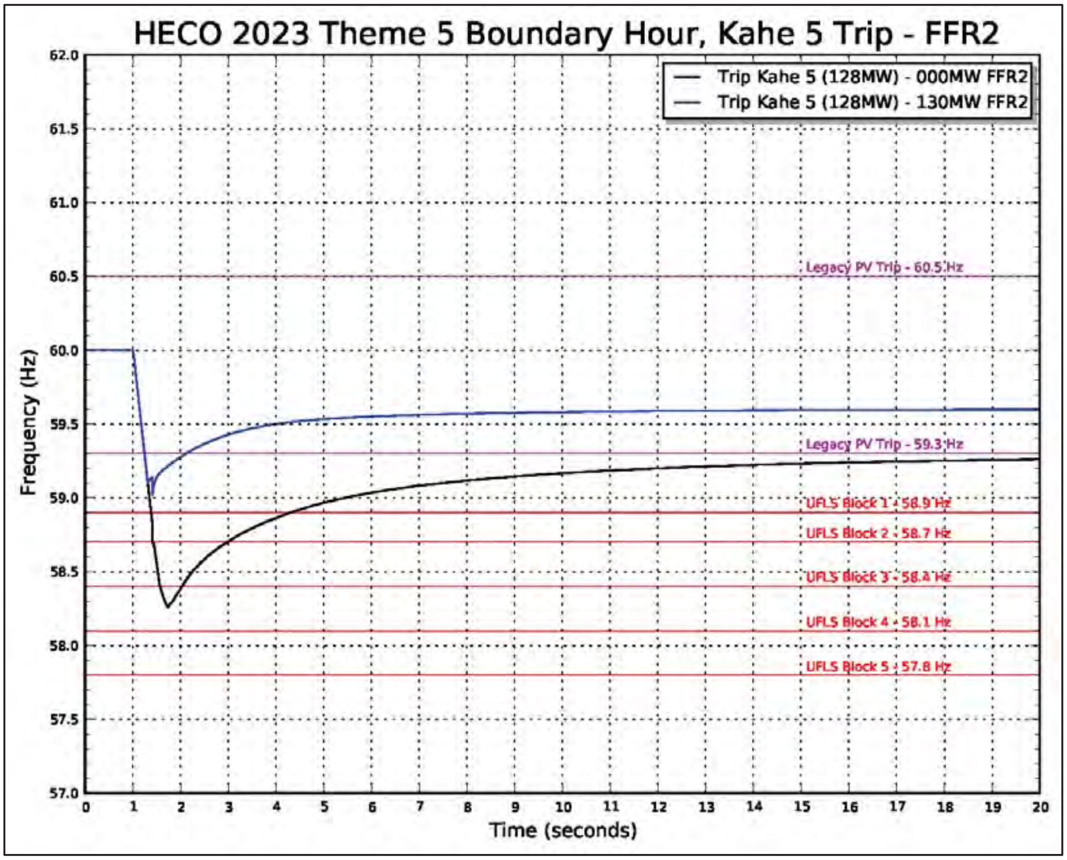

Figure O-91. Frequency Response Profile FFR2 Boundary Hour

Figure O-91 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

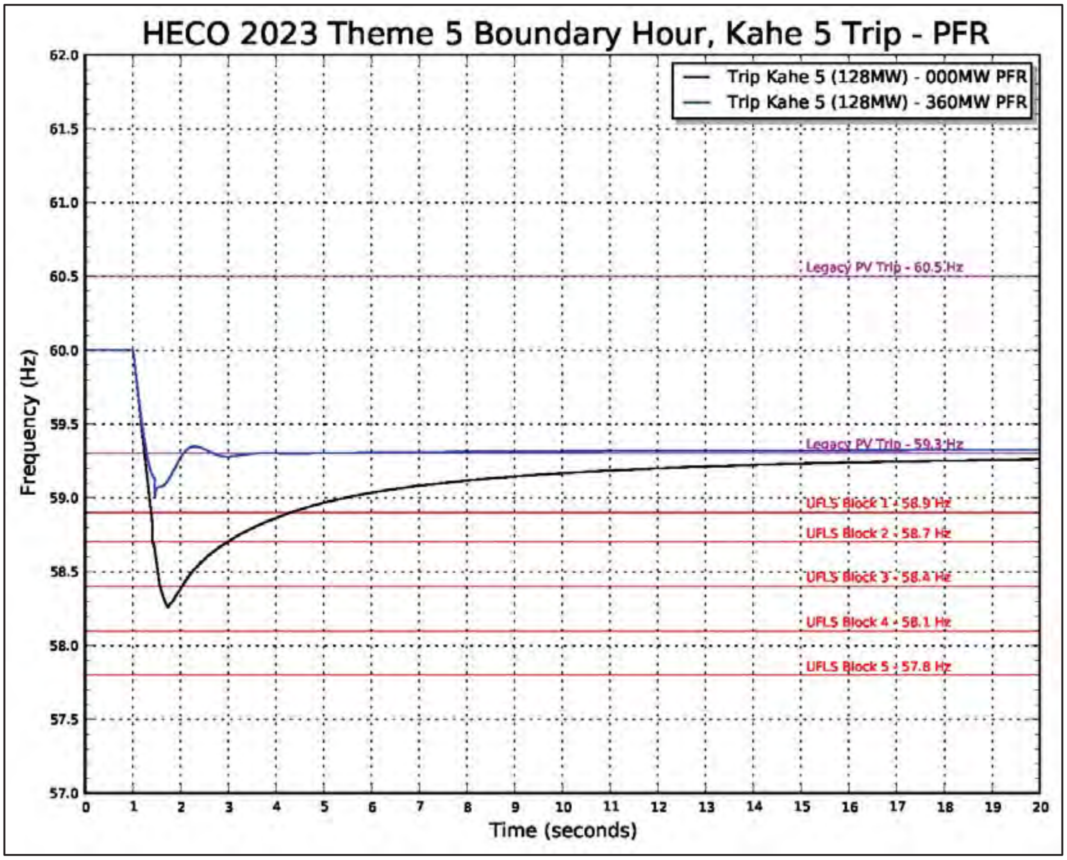

Figure O-92. Frequency Response Profile PFR Boundary Hour

Figure O-92 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 360 MW. This is in addition to the 26 MW of upward regulation from thermal generation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

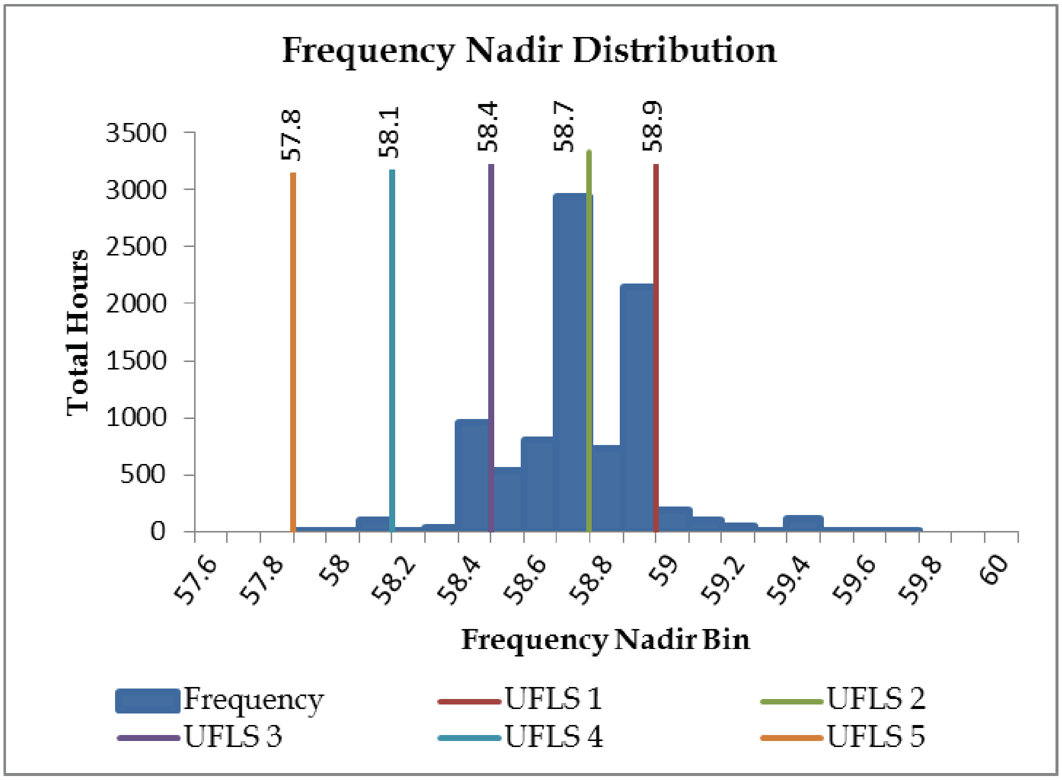

Figure O-93. Frequency Nadir Histogram 2025

Figure O-93 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 952 hours was 10:00 AM on Wednesday, December 24. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 2 hours was 3:00 AM on Sunday, March 16. The frequency nadir range for the boundary hour is 57.8 – 57.9 Hz that requires five blocks of UFLS to stabilize system frequency.

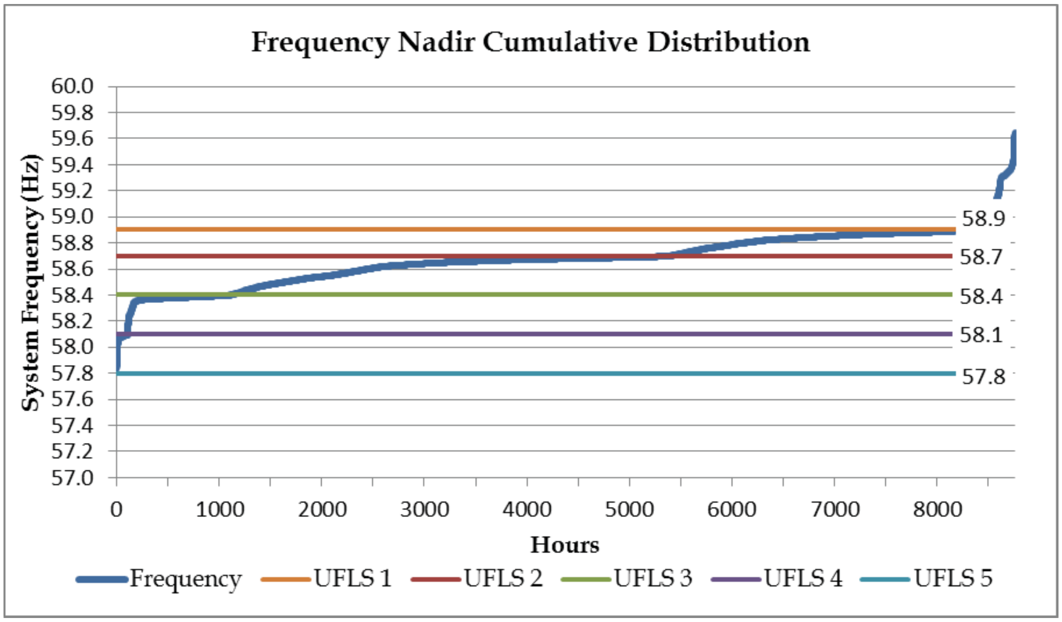

Figure O-94. Frequency Nadir Duration Curve 2025

Figure O-94 shows the frequency nadir duration curve for 2025. The system is at risk of UFLS for 8267 hours of the year.

Unit	Unit Ratings							Theme 5 - GE CT1 Trip Typical Wed 12/24/25 Hour 10			Theme 5 - GE CT1 Trip Boundary Sun 3/16/25 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.2	1.8	53.2	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.1	0.9	29.1	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.2	1.8	53.2	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 2	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 3	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 4	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 5	16.8	6.7			0.99	21.8	22				13.5	3.3	6.9
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	0.0			2.43	11.8	29	0.0	10.0	0.0	0.0	10.0	0.0
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	0.0	0.0			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	0.0	0.0			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 6	0.0	0.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						44			55		
-Kahuku	30	0						17			12		
-Kawailoa	69	0						19			14		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	786	0						227			0		
Station PV	687	0						236			0		
Total Kinetic Energy								3446			3410		
Total Load								930			530		
Total Thermal Generation								423			475		
Total Renewable Generation								507			55		
Total Generation								930			530		
Excess Generation								0			0		
Total Up Regulation								15			24		
Total Down Regulation								249			277		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		22.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		64.8	60.5Hz Output		0.0

Table O-40. Unit Commitment and Dispatch 2025

Table O-40 shows the unit commitment and dispatch for the typical hour 12/24/25, 10:00 AM) and boundary hour (3/16/25, 3:00 AM).

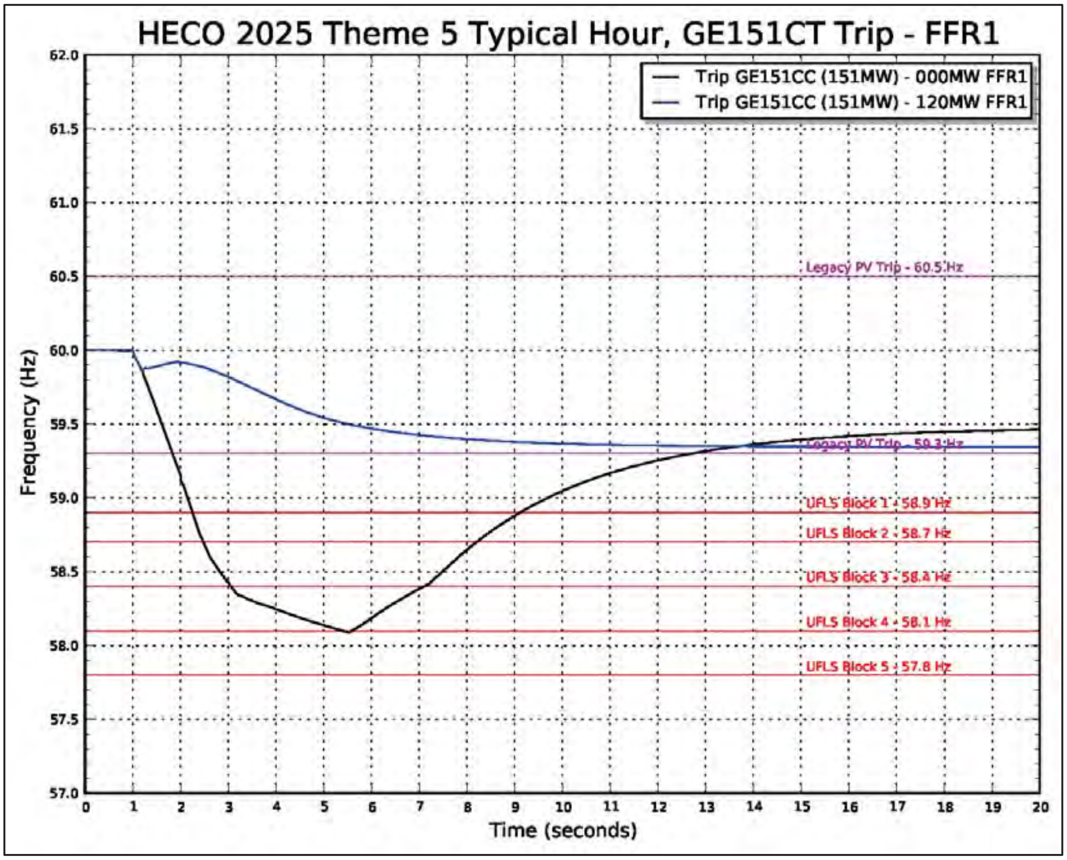

Figure O-95. Frequency Response Profile FFR1 Typical Hour

Figure O-95 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 3446 MW-sec and the capacity of legacy PV that will disconnect from the system is 22 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

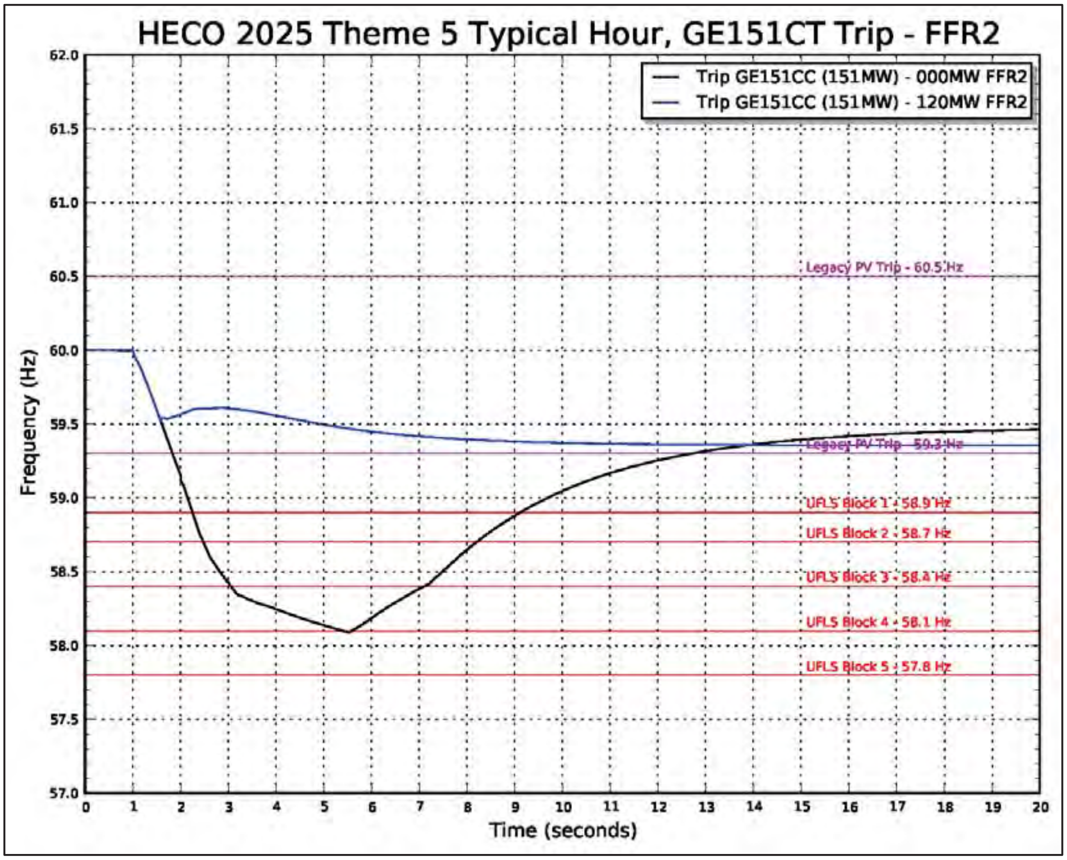

Figure O-96. Frequency Response Profile FFR2 Typical Hour

Figure O-96 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

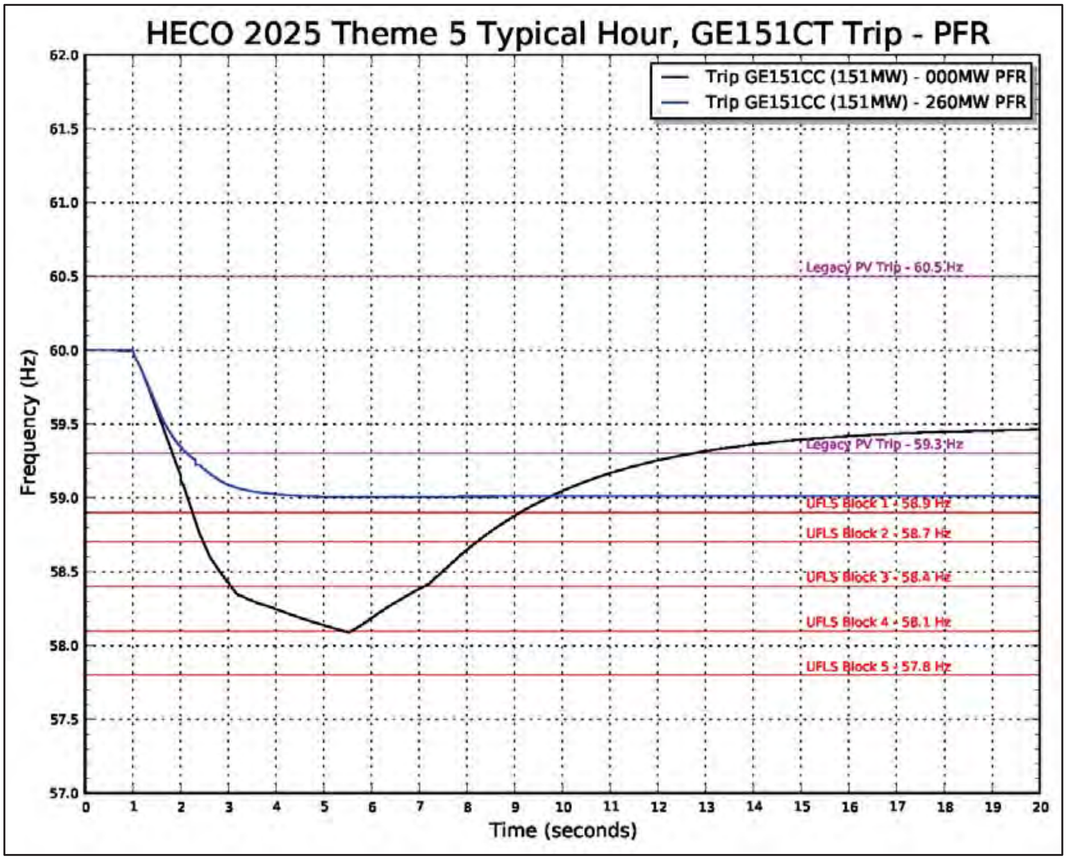

Figure O-97. Frequency Response Profile PFR Typical Hour

Figure O-97 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 15 MW of upward regulation from thermal generation.

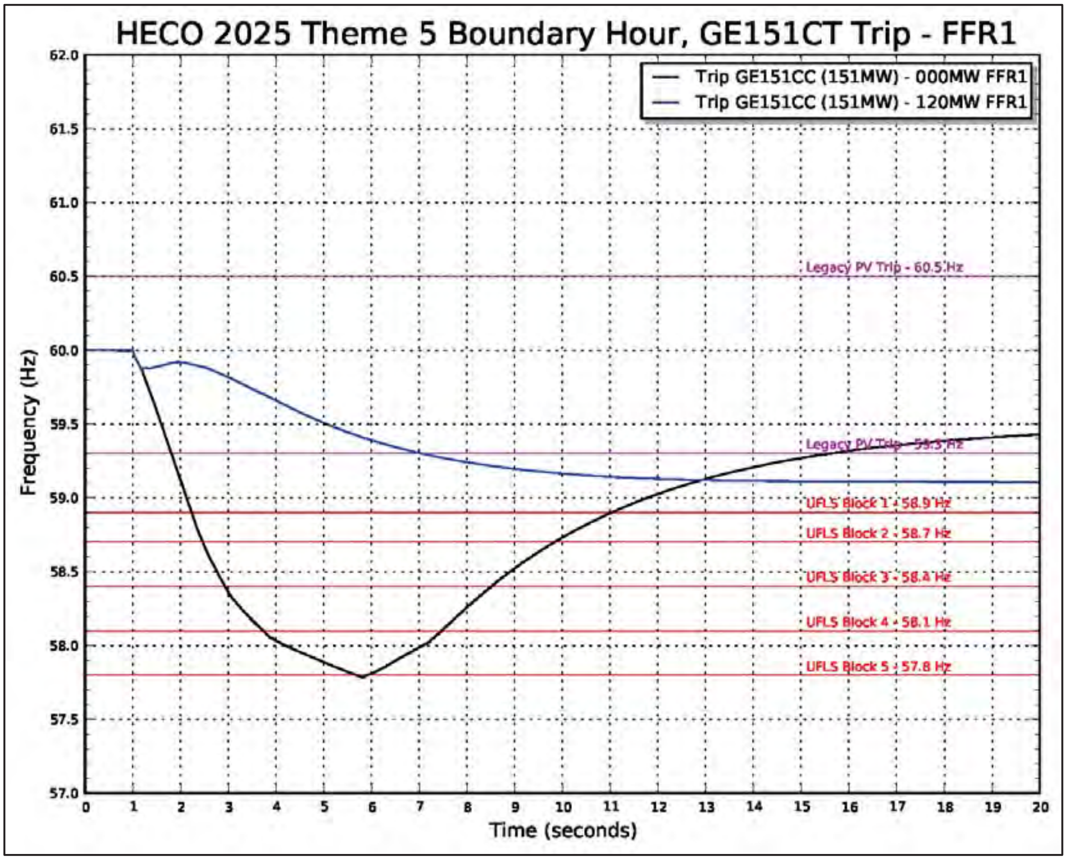

Figure O-98. Frequency Response Profile FFR1 Boundary Hour

Figure O-98 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3410 MW-sec. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

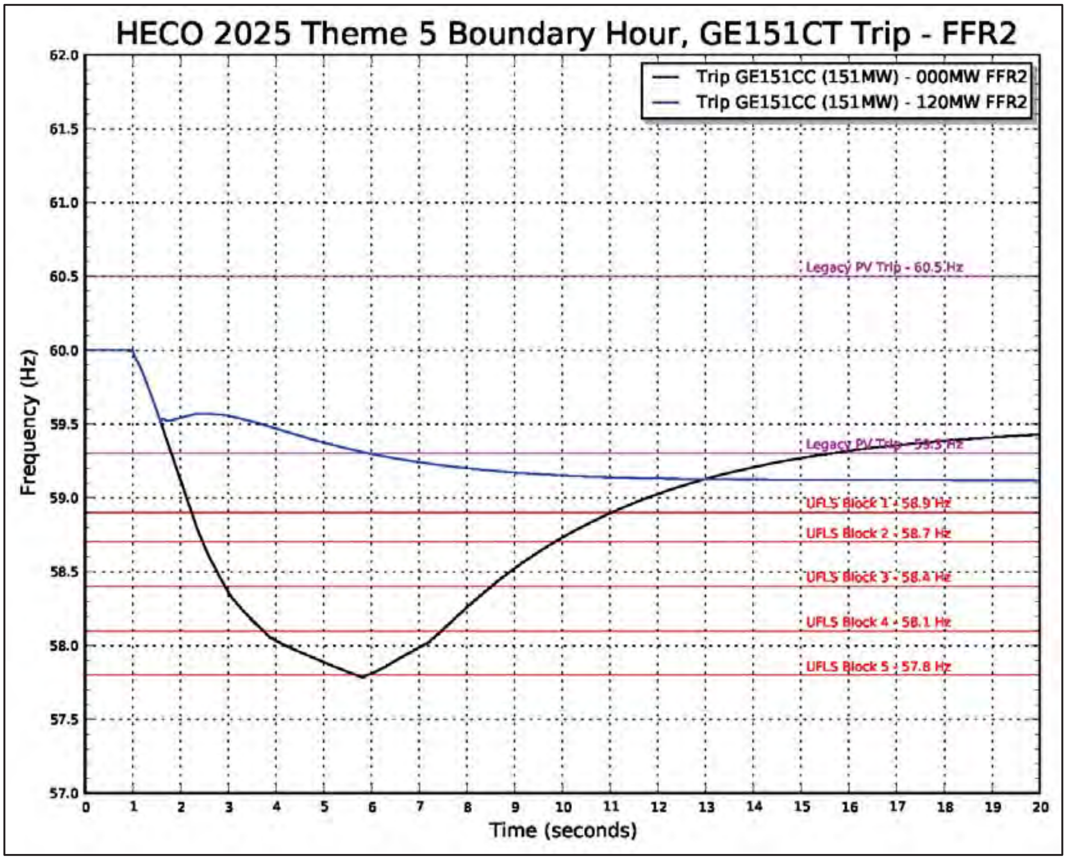

Figure O-99. Frequency Response Profile FFR2 Boundary Hour

Figure O-99 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

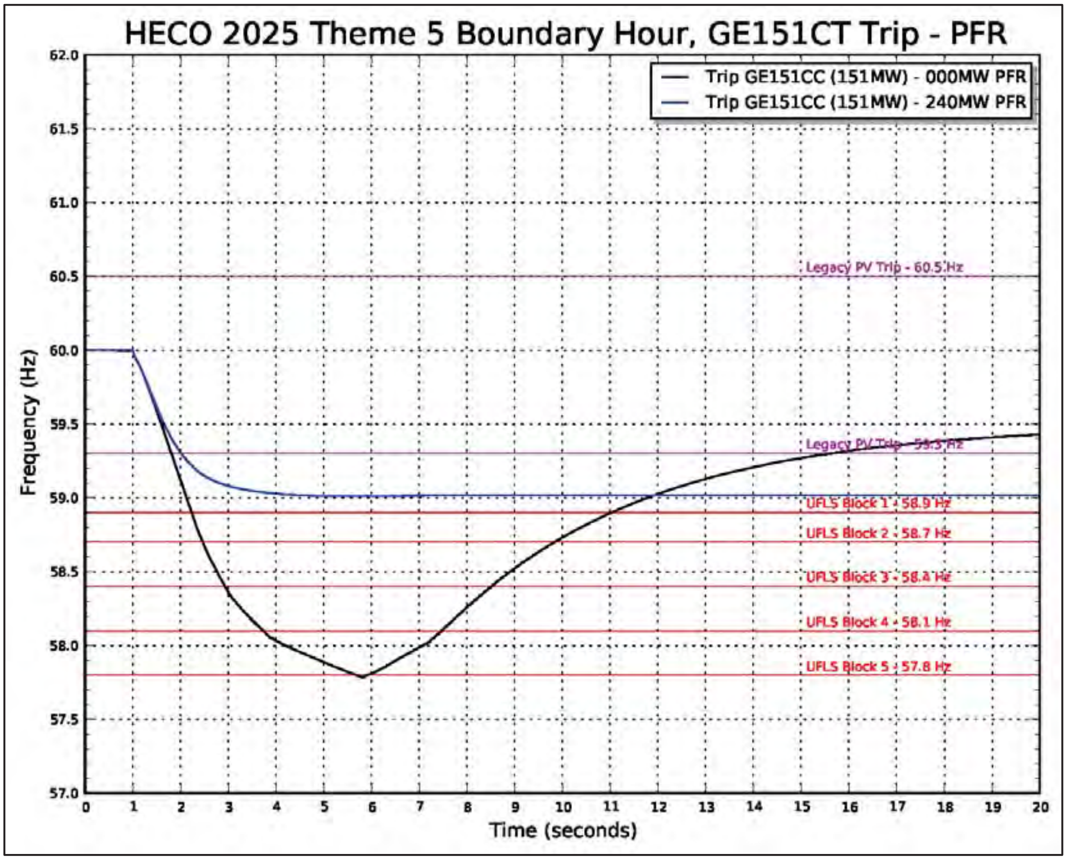

Figure O-100. Frequency Response Profile PFR Boundary Hour

Figure O-100 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 240 MW. This is in addition to the 24 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

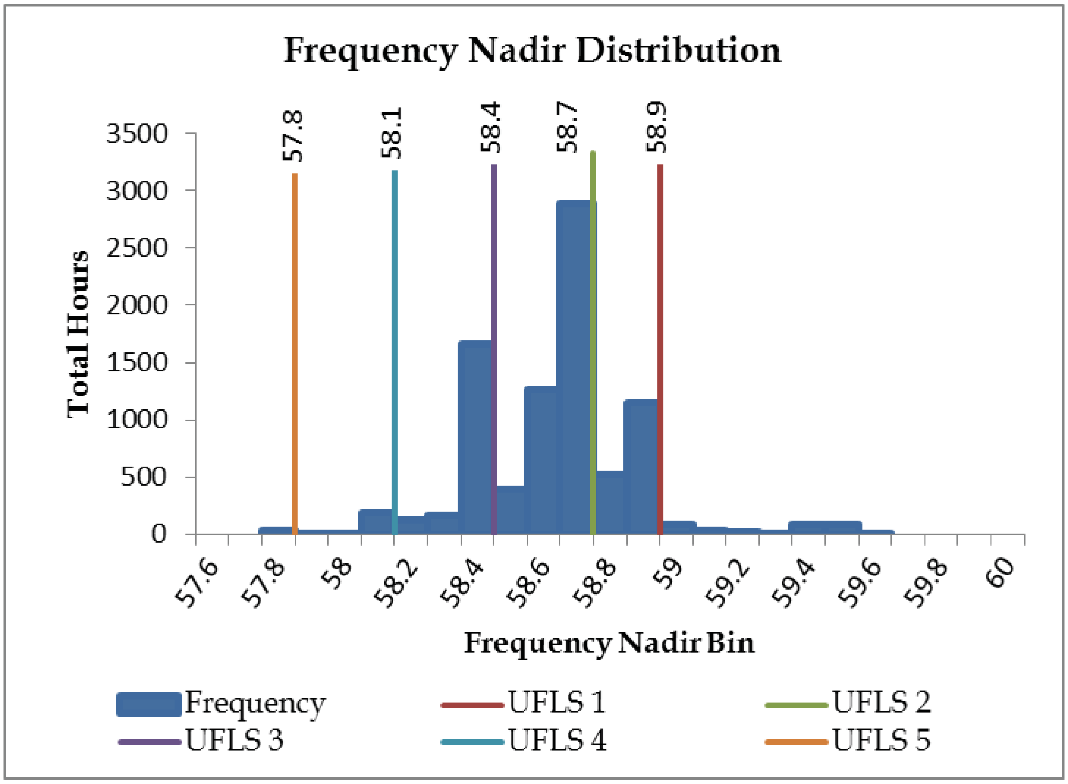

Figure O-101. Frequency Nadir Histogram 2030

Figure O-101 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1655 hours was 5:00 PM on Tuesday, March 29. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 37 hours was 4:00 AM on Monday, March 4. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

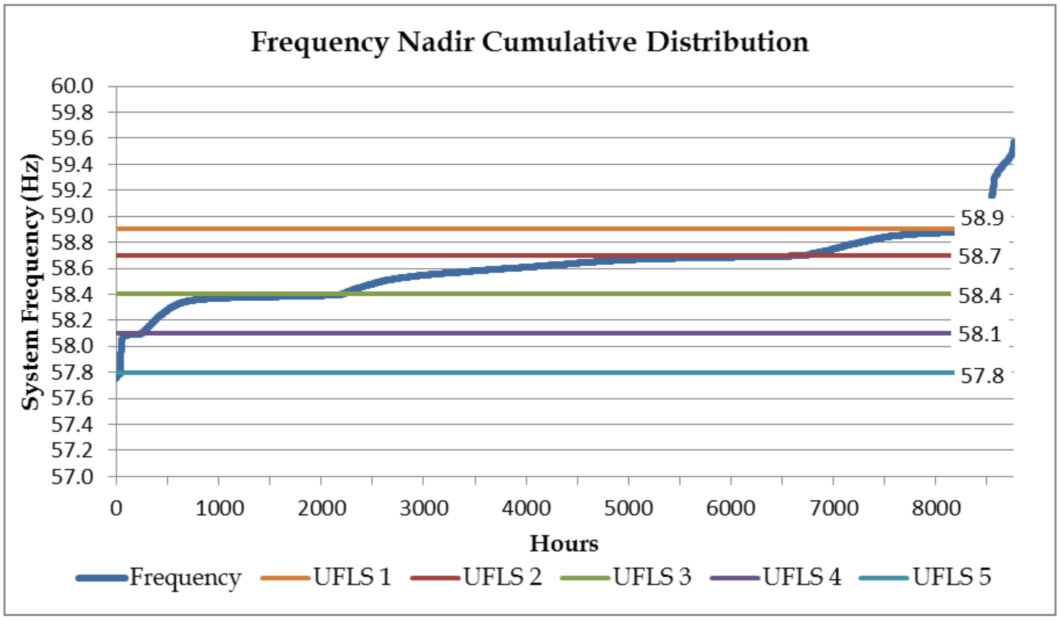

Figure O-102. Frequency Nadir Duration Curve 2030

Figure O-102 shows the frequency nadir duration curve for 2030. The system is at risk of UFLS for 8414 hours of the year.

Unit	Unit Ratings							Theme 5 - GE CT1 Trip Typical Fri 3/29/30 Hour 17			Theme 5 - GE CT1 Trip Boundary Mon 3/4/30 Hour 4		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335	83.4	0.6	41.4	84.0	0.0	42.0
GE-151ST2	67.0	29.0			4.70	99.3	467	60.7	6.3	31.7	67.0	0.0	38.0
GE-151CT3	84.0	42.0			3.40	98.5	335				83.8	0.2	41.8
GE-151ST3	67.0	29.0			4.70	99.3	467				64.1	2.9	35.1
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	0.0			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						39			18		
-Kahuku	30	0						4			1		
-Kawailoa	69	0						8			9		
-Na Pua Makani	24	0						14			0		
-CBRE Wind	10	0						3			2		
DG-PV	867	0						259			0		
Station PV	847	0						355			0		
Total Kinetic Energy								2777			3435		
Total Load								1016			502		
Total Load Shifting								0			0		
Total Thermal Generation								364			485		
Total Renewable Generation								653			18		
Total Generation								1016			502		
Excess Generation								0			0		
Total Up Regulation								7			14		
Total Down Regulation								187			247		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		22.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		64.8	60.5Hz Output		0.0

Table O-41. Unit Commitment and Dispatch 2030

Table O-41 shows the unit commitment and dispatch for the typical hour (3/29/30, 5:00 PM) and boundary hour (3/4/30, 4:00 AM).

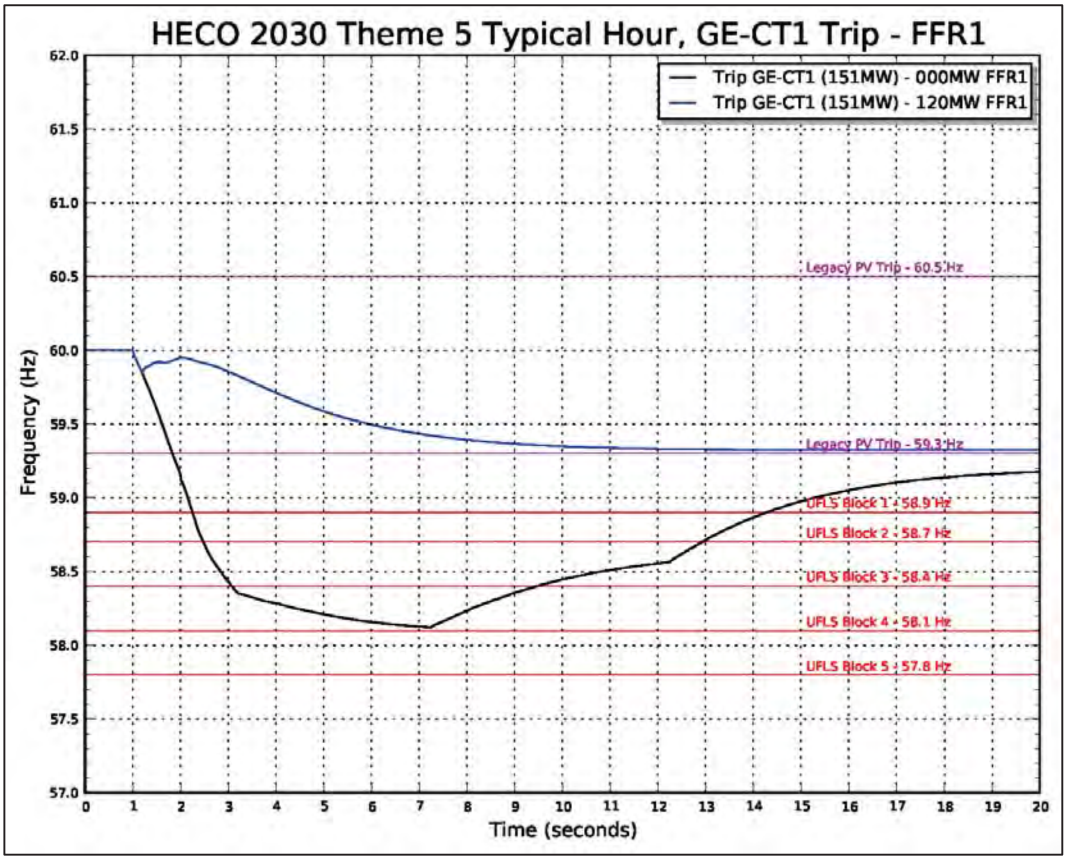

Figure O-103. Frequency Response Profile FFR1 Typical Hour

Figure O-103 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 2777 MW-sec and the capacity of legacy PV that will disconnect from the system is 22 MW. With no FFR, the frequency nadir breaches 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

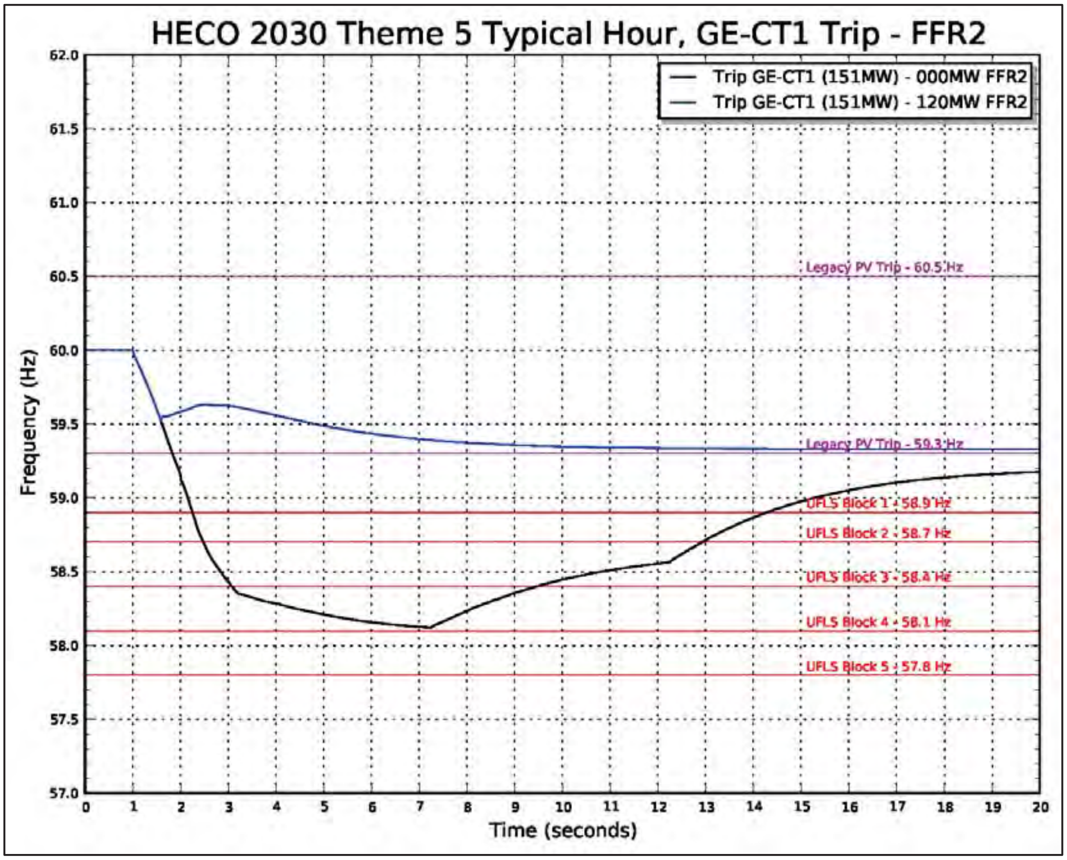

Figure O-104. Frequency Response Profile FFR2 Typical Hour

Figure O-104 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

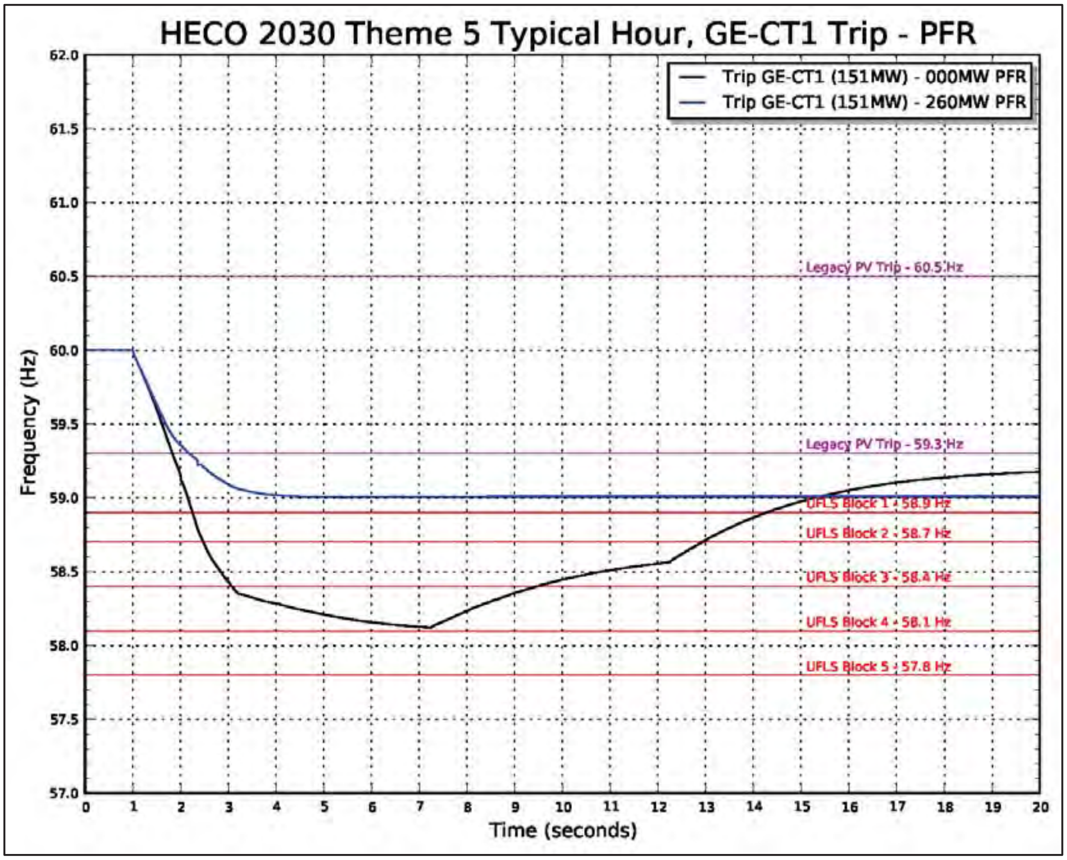

Figure O-105. Frequency Response Profile PFR Typical Hour

Figure O-105 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 7 MW of upward regulation from thermal generation.

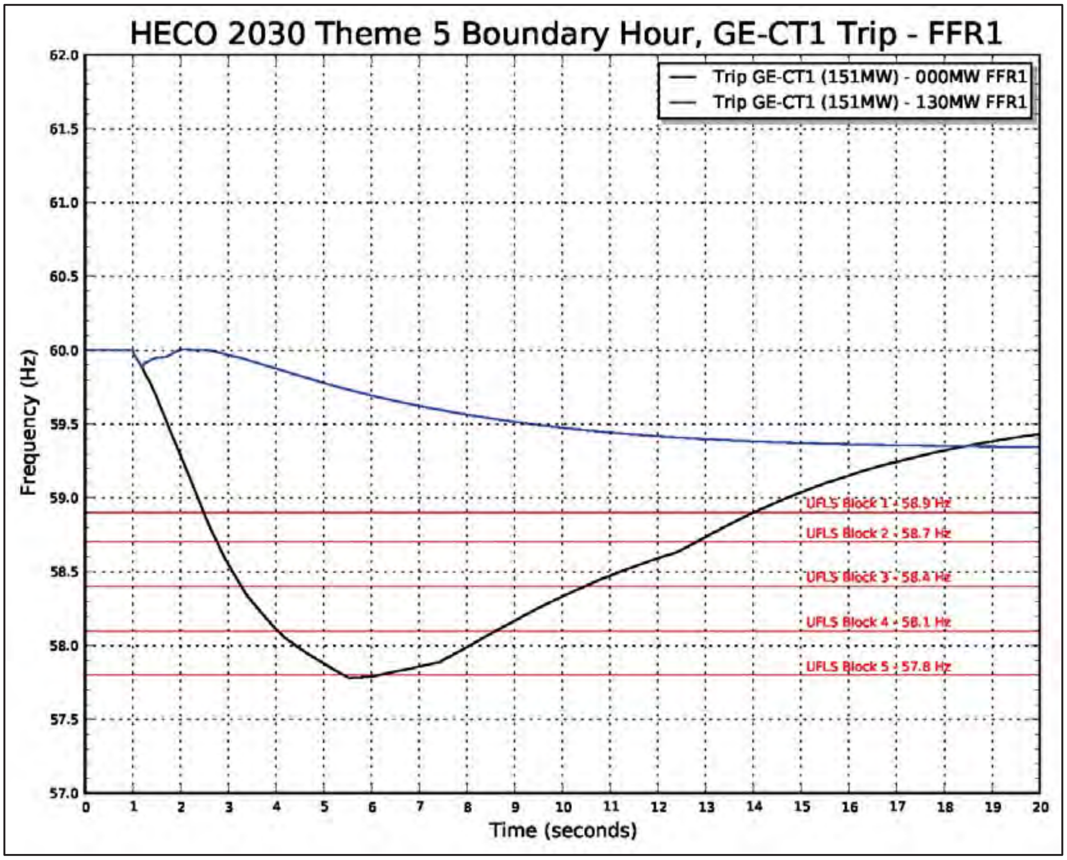

Figure O-106. Frequency Response Profile FFR1 Boundary Hour

Figure O-106 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3435 MW-sec. With no FFR, the frequency nadir breaches 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 130 MW.

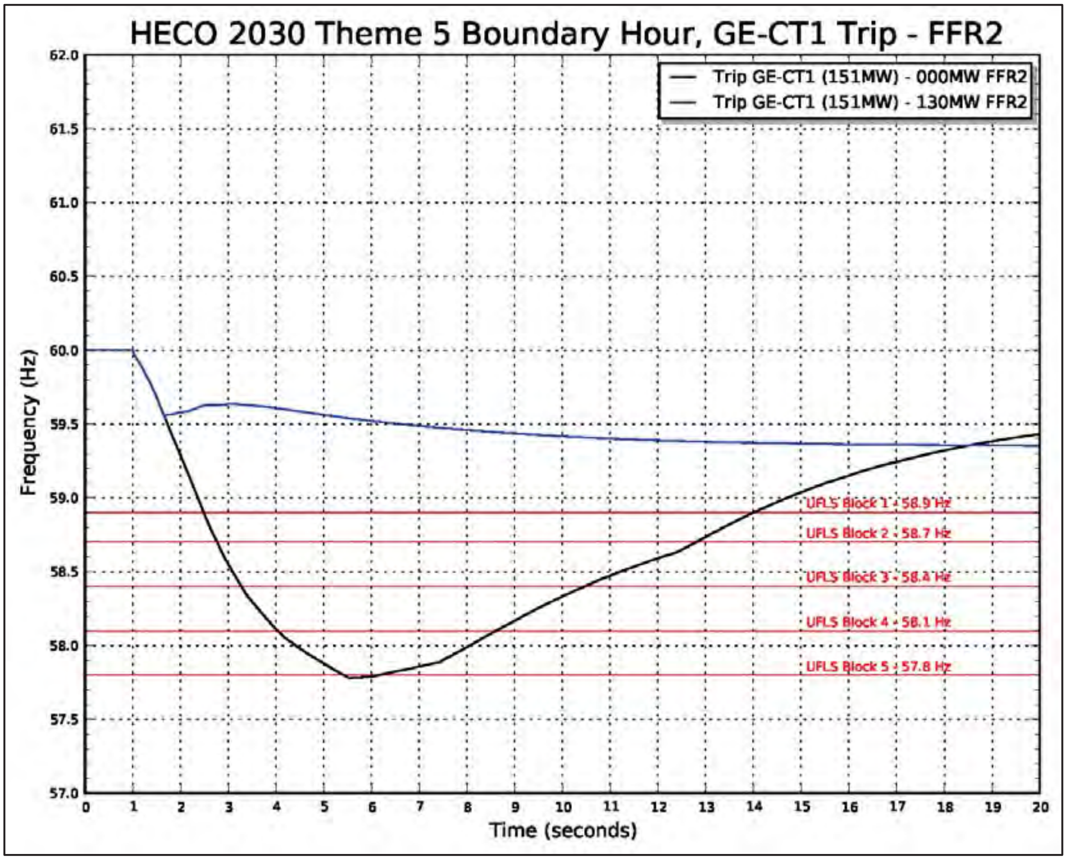

Figure O-107. Frequency Response Profile FFR2 Boundary Hour

Figure O-107 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

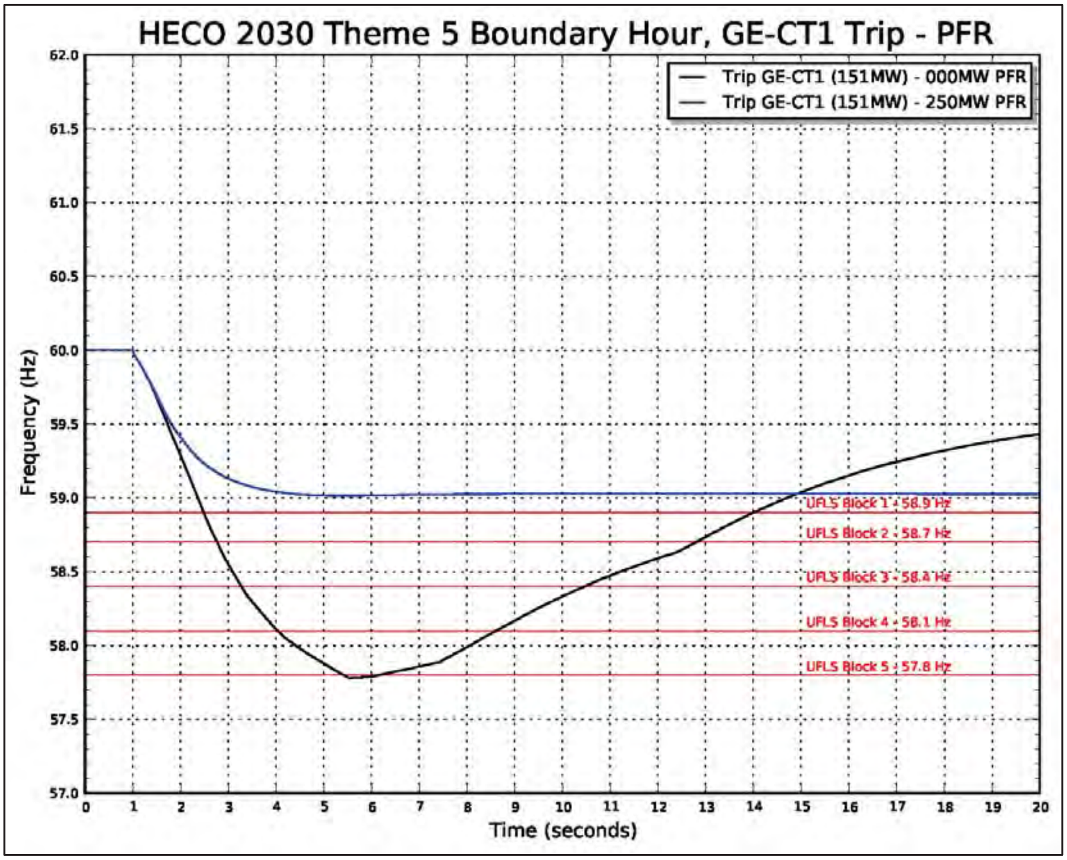

Figure O-108. Frequency Response Profile PFR Boundary Hour

Figure O-108 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 250 MW. This is in addition to the 14 MW of upward regulation in from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

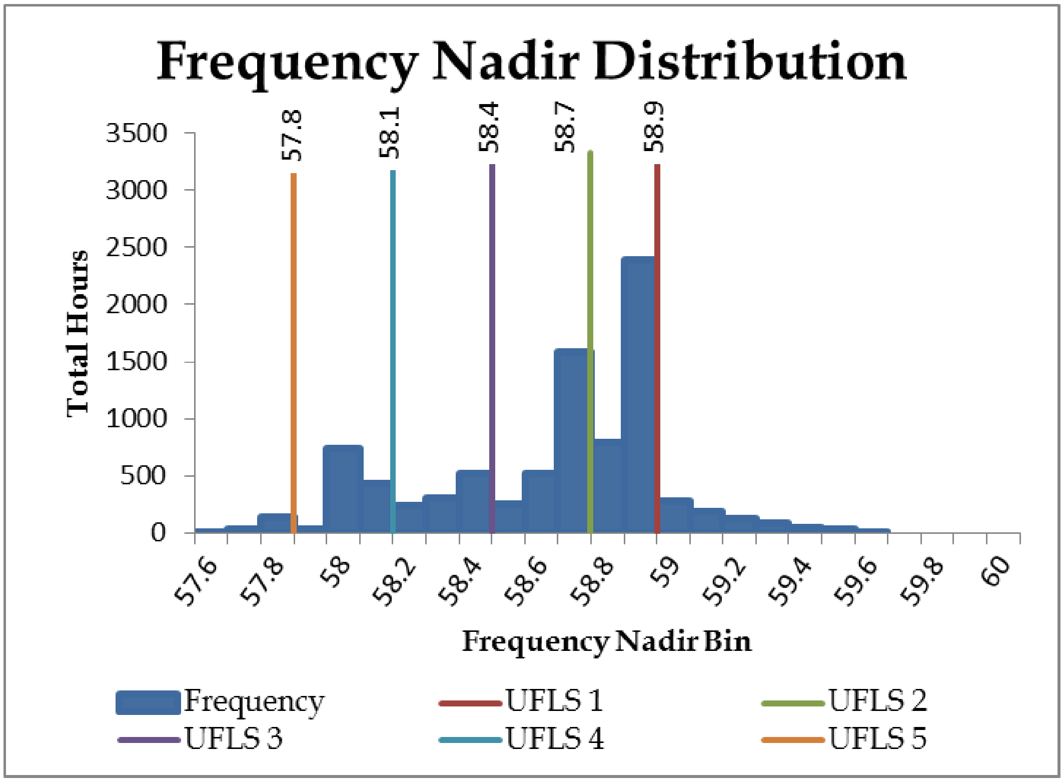

Figure O-109. Frequency Nadir Histogram 2045

Figure O-109 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 737 hours was 2:00 AM on Wednesday, October 4. The frequency nadir range for the typical hour is 57.9- 58.0 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 1 hour was 3:00 AM on Friday, January 27. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

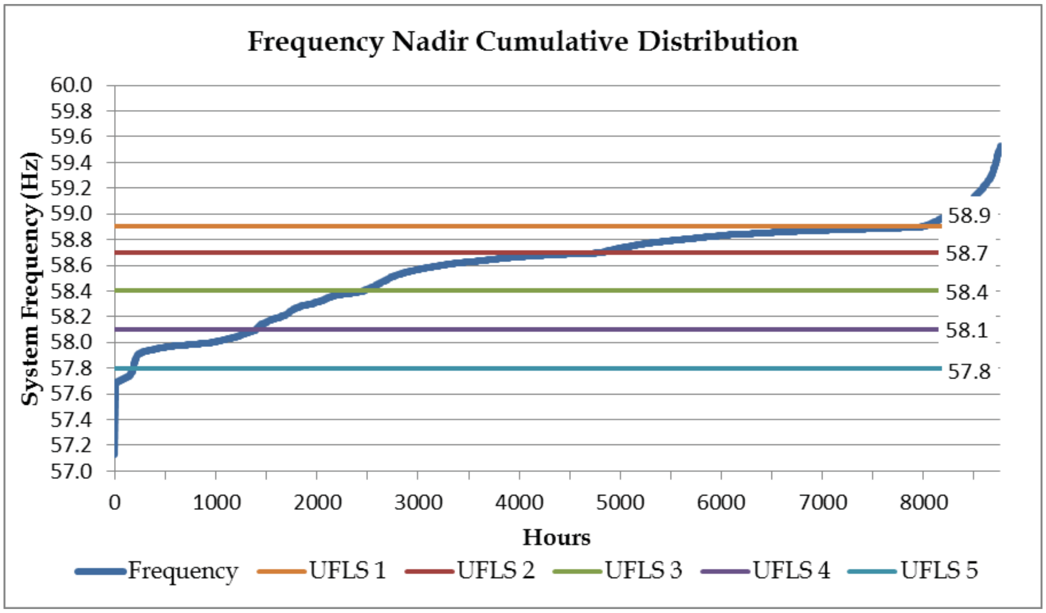

Figure O-110. Frequency Nadir Duration Curve 2045

Figure O-110 shows the frequency nadir duration curve for 2045. The system is at risk of UFLS for 7995 hours of the year.

Unit	Unit Ratings					Theme 5 - Off Shore Wind Trip Typical Wed 10/4/45 Hour 2			Theme 5 - Off Shore Wind TripBoundary Fri 1/27/45 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0	2.78	75.0	209	35.0	11.0	10.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0	3.41	42.1	144						
Kalaeloa CT-1	84.0	29.0	4.96	119.2	591						
Kalaeloa ST	40.0	10.0	4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0	4.96	119.2	591						
Waiau 9	52.9	5.9	7.84	57.0	447						
Waiau 10	49.9	5.9	7.84	57.0	447						
CIP1	112.2	41.2	4.72	162.0	765						
Schofield 1	8.0	2.0	0.99	10.9	11						
Schofield 2	8.0	2.0	0.99	10.9	11						
Schofield 3	8.0	2.0	0.99	10.9	11						
Schofield 4	8.0	2.0	0.99	10.9	11						
Schofield 5	8.0	2.0	0.99	10.9	11						
Schofield 6	8.0	2.0	0.99	10.9	11						
JBPHH 1	16.8	6.7	0.99	21.8	22						
JBPHH 2	16.8	6.7	0.99	21.8	22						
JBPHH 3	16.8	6.7	0.99	21.8	22						
JBPHH 4	16.8	6.7	0.99	21.8	22						
JBPHH 5	16.8	6.7	0.99	21.8	22						
JBPHH 6	16.8	6.7	0.99	21.8	22						
KMCBH 1	9.2	4.6	0.99	10.9	11						
KMCBH 2	9.2	4.6	0.99	10.9	11						
KMCBH 3	9.2	4.6	0.99	10.9	11						
KMCBH 4	9.2	4.6	0.99	10.9	11						
KMCBH 5	9.2	4.6	0.99	10.9	11						
KMCBH 6	9.2	4.6	0.99	10.9	11						
GE-151CT1	84.0	42.0	3.40	98.5	335						
GE-151ST1	67.0	29.0	4.70	99.3	467						
GE-151CT2	84.0	42.0	3.40	98.5	335						
GE-151ST2	67.0	29.0	4.70	99.3	467						
GE-151CT3	84.0	42.0	3.40	98.5	335						
GE-151ST3	67.0	29.0	4.70	99.3	467						
GE-151CT4	84.0	42.0	3.40	98.5	335						
GE-151ST4	67.0	29.0	4.70	99.3	467						
GE-151CT5	84.0	42.0	3.40	98.5	335						
GE-151ST5	67.0	29.0	4.70	99.3	467						
PSH	10.0	-10.0	2.43	11.8	29	-10.0			-10.0		
Kahe 6	133.8	40.0	1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7	2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5	2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0	1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0	1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	963	0				680			683		
-Kahuku	30	0				0			3		
-Kawailoa	69	0				8			17		
-Na Pua Makani	24	0				10			1		
-CBRE Wind	10	0				0			0		
DG-PV	1106	0				0			0		
Station PV	1047	0				0			0		
Total Kinetic Energy							1002			1002	
Total Load							705			508	
Total Load Shifting							0			-200	
Total Thermal Generation							25			25	
Total Renewable Generation							680			683	
Total Generation							705			708	
Excess Generation							0			0	
Total Up Regulation							11			11	
Total Down Regulation							10			10	
Legacy DG-PV		59.3Hz Capacity	0.0			59.3Hz Output		0.0	59.3Hz Output		0.0
		60.5Hz Capacity	0.0			60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-42. Unit Commitment and Dispatch 2045

Table O-42 shows the unit commitment and dispatch for the typical hour (10/4/45, 2:00 AM) and boundary hour (1/27/45, 3:00 AM).

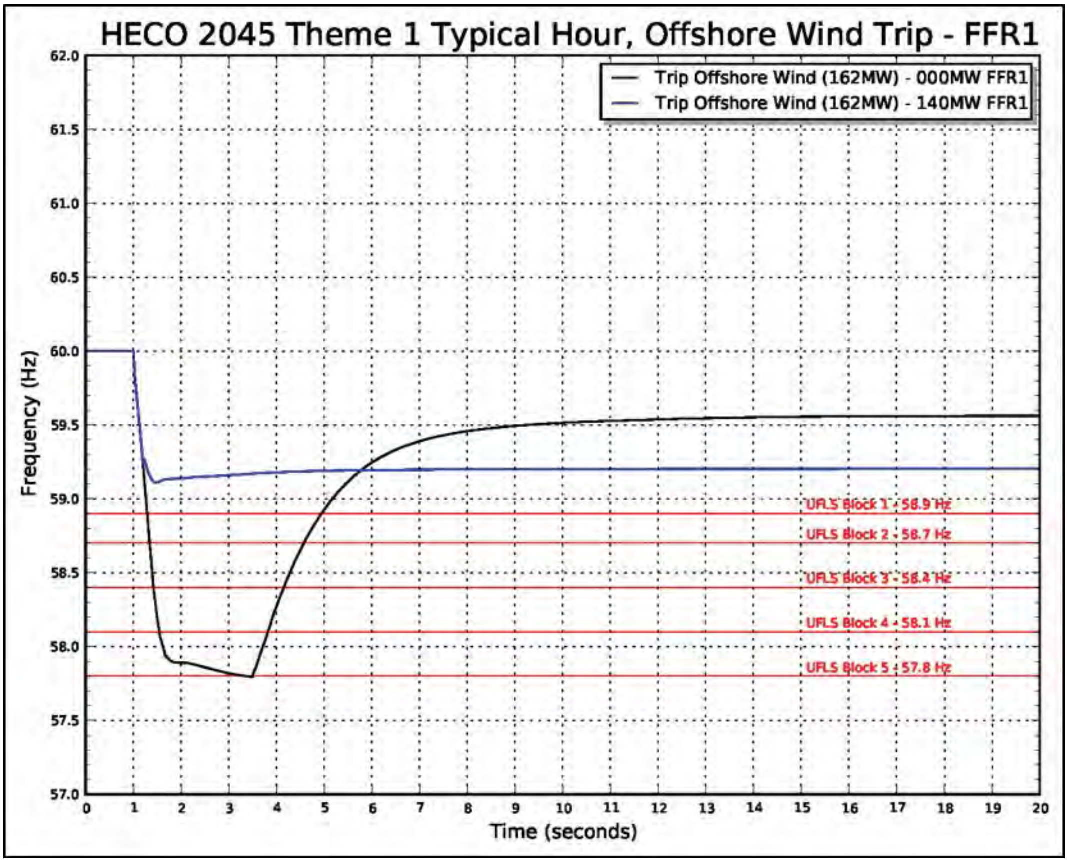

Figure O-111. Frequency Response Profile FFR1 Typical Hour

Figure O-111 shows the frequency response profile for an off-shore wind trip at 162 MW in for a typical hour. System kinetic energy is 1002 MW-sec. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

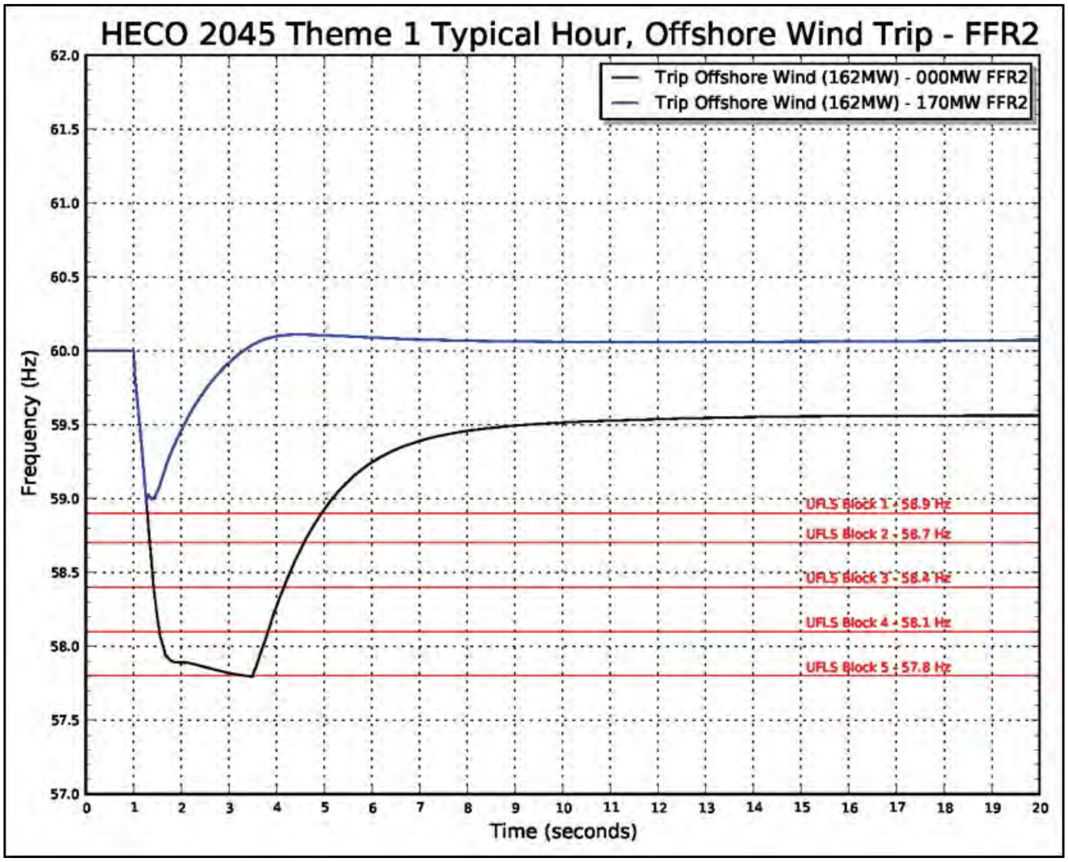

Figure O-112. Frequency Response Profile FFR2 Typical Hour

Figure O-112 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

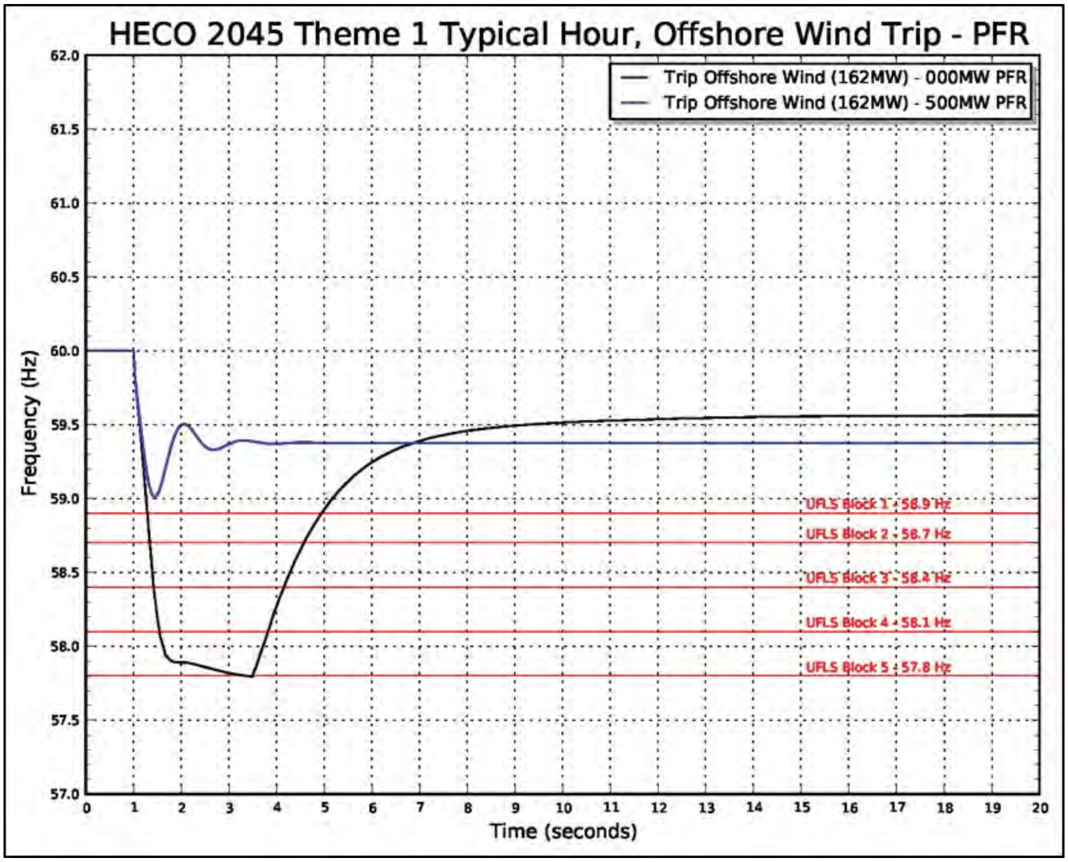

Figure O-113. Frequency Response Profile PFR Typical Hour

Figure O-113 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 500 MW. This is in addition to the 11 MW of upward regulation from thermal generation.

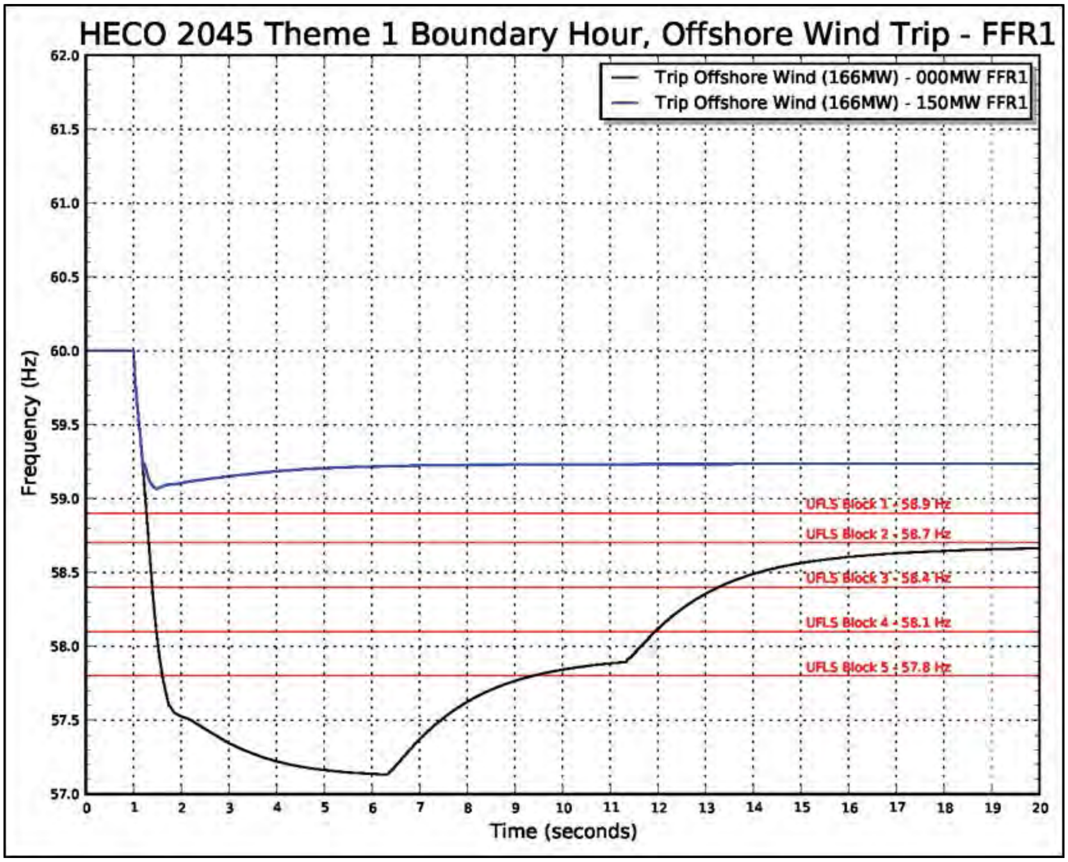

Figure O-114. Frequency Response Profile FFR1 Boundary Hour

Figure O-114 shows the frequency response profile for an off-shore wind trip at 166 MW for a boundary hour. System kinetic energy is 1002 MW-sec. With no FFR, the frequency nadir is 57.2 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

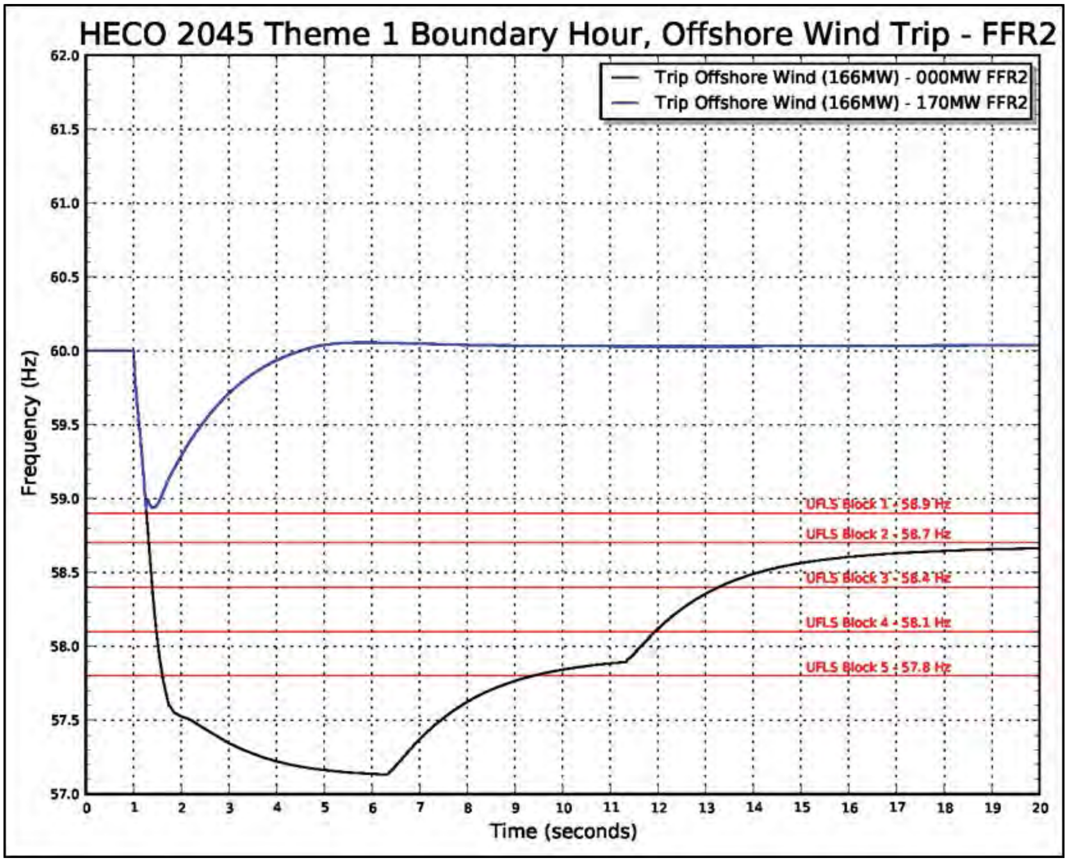

Figure O-115. Frequency Response Profile FFR2 Boundary Hour

Figure O-115 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

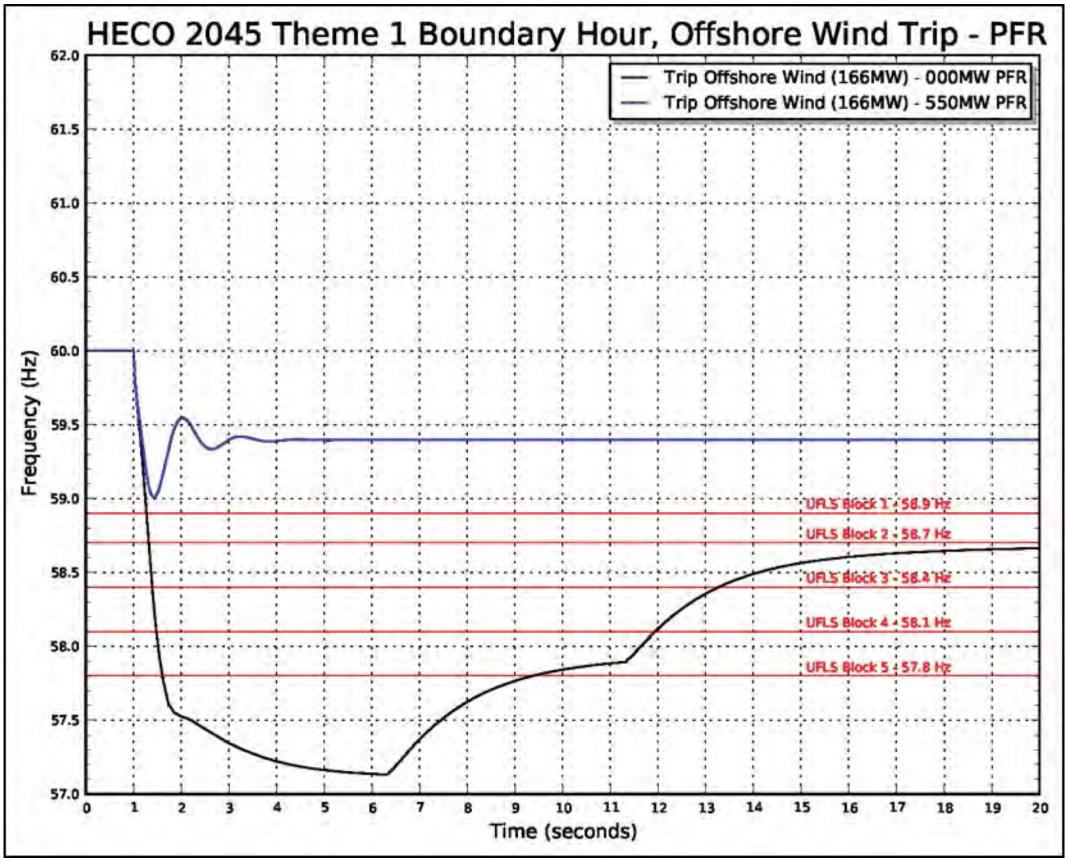

Figure O-116. Frequency Response Profile PFR Boundary Hour

Figure O-116 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 550 MW. This is in addition to the 11 MW of upward regulation from thermal generation.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR - QV Dispatch Wed 1/2/2019 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	188.8	0.2	125.8
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	65.0	19.0	36.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.0	12.0	18.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	65.0	19.0	36.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	31.4	50.8	7.6
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	35.3	50.0	11.7
Kahe 5	134.6	21.0			4.36	158.8	692	96.9	37.7	75.9
Kahe 6	133.8	40.0			4.36	158.8	692	67.1	66.7	27.1
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	133.0	0.0						28.7		
-Kahuku	30.0	0.0						7.8		
-Kawailoa	69.0	0.0						17.9		
-Na Pua Makani	24.0	0.0								
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	0.0	0.0								
-Offshore Wind	0.0	0.0								
Total Station PV	182.2	0.0						118.2		
-KS2	5.0	0.0						2.9		
-KREP	5.0	0.0						2.3		
-Waianae	27.6	0.0						17.1		
-Kawailoa PV	49.0	0.0						30.0		
-Mililani 2	14.7	0.0						8.0		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						16.1		
-CBRE PV	15.0	0.0						11.8		
-Future PV	0.0	0.0								
DG-PV	654.6	0.0						207.7		
Total Kinetic Energy								4961		
Total Load								1032		
Total Thermal Generation								677		
Total Renewable Generation								355		
Total Generation								1032		
Excess Generation								0		
Total Up Regulation								310		
Total Down Regulation								379		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		23.3
	60.5Hz Capacity			215.9				60.5Hz Output		68.5

Table O-43. Unit Commitment and Dispatch 2019 QV Analysis

Table O-43 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Wed 1/2/2019 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	25.9	73.5	-75.7
Kalaeloa CT-1	84.5	-35.9	13.9	70.6	-49.8
Kalaeloa ST	42.1	-16.7	13.9	28.2	-30.6
Kalaeloa CT-2	84.5	-35.8	13.9	70.6	-49.7
Kahe 1	67.0	-51.2	17.4	49.6	-68.6
Kahe 2	64.4	-50.3			
Kahe 3	71.2	-21.3	17.4	53.8	-38.6
Kahe 4	63.8	-20.5	17.4	46.4	-37.9
Kahe 5	96.6	-63.4	79.1	17.5	-142.4
Kahe 6	107.7	-61.9	38.5	69.3	-100.4
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	87.4	-110.9	6.4	64.6	-101.9
-Kahuku	17.9	-17.9	3.7	14.2	-21.6
-Kawailoa	50.0	-74.5	2.7	47.3	-77.2
-Na Pua Makani	16.4	-15.4			
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	5.2	104.2	-114.6
-KS2	1.6	-1.6	-0.1	1.7	-1.5
-KREP	2.0	-2.0	1.5	0.5	-3.5
-Waianae	14.5	-14.5	1.1	13.4	-15.6
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	-0.4	11.1	-10.3
-Waiawa	32.9	-32.9	1.1	31.8	-34.0
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.7
-Future PV	0.0	0.0			
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			242.9		
Total Renewable MVAR Generation			11.6		
Total Cap Bank MVAR			186.1		
Charging MVAR			77.4		
Total MVAR Supply			518.1		
Total MVAR Load			336.2		
Total MVAR Losses			181.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				706.5	
Total MVAR Absorb Capability					-832.0

Table O-44. MVAR Capability 2019 QV Analysis

Table O-44 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1

Table O-45. N-2 Contingencies 2019 QV Analysis

Table O-45 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

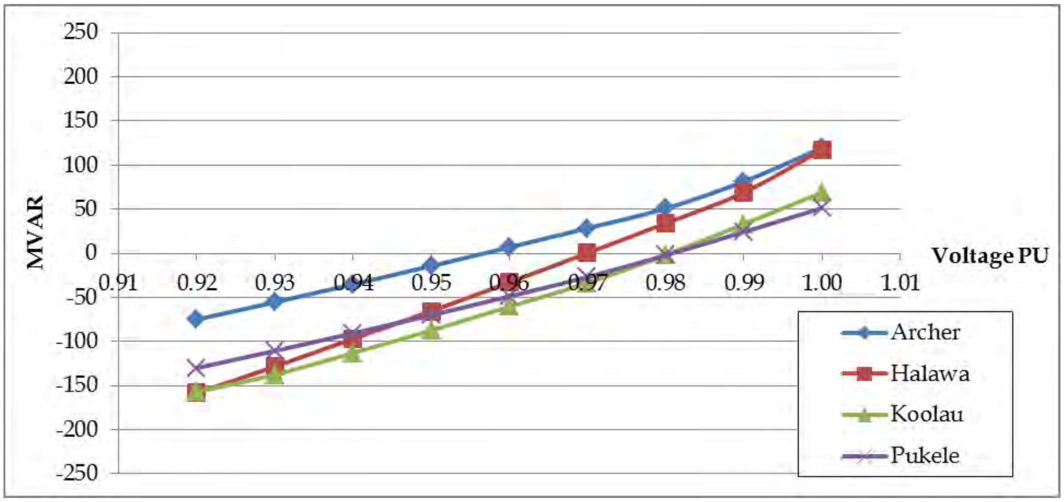

Figure O-117. QV Curves 2019

Figure O-117 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	120	125	82	135	51	135	29	135	7	135	-14	135	-35	135	-55	135	-75
120	Halawa	125	118	154	69	154	34	154	0	154	-33	154	-66	154	-97	154	-128	154	-158
150	Koolau	125	69	125	33	125	-2	125	-33	125	-60	125	-87	125	-113	125	-138	203	-157
170	Pukele	125	51	125	24	125	-2	125	-27	125	-49	125	-70	125	-91	125	-111	125	-130

Table O-46. Summary of Results 2019 QV Analysis

Table O-46 shows the results of the 2019 QV analysis. The unit commitment and dispatch is able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

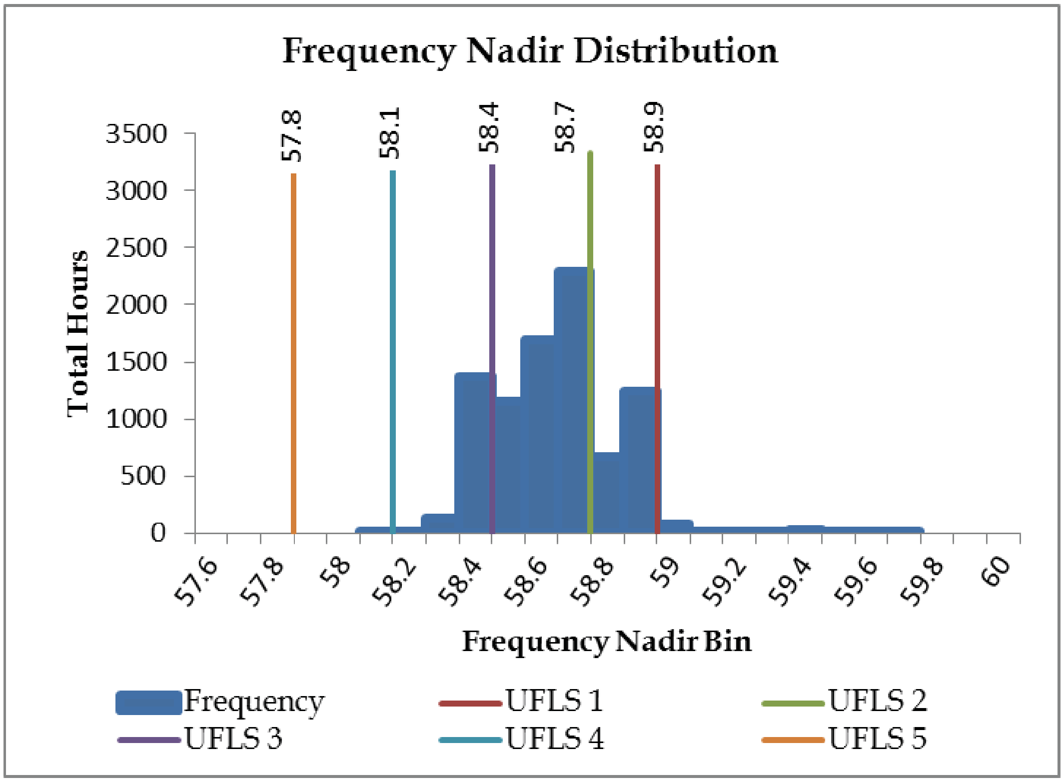

Figure O-118. Frequency Nadir Histogram 2019

Figure O-118 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1370 hours was 2:00 PM on Thursday, March 21. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 3 hours was 3:00 AM on Tuesday, March 19. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

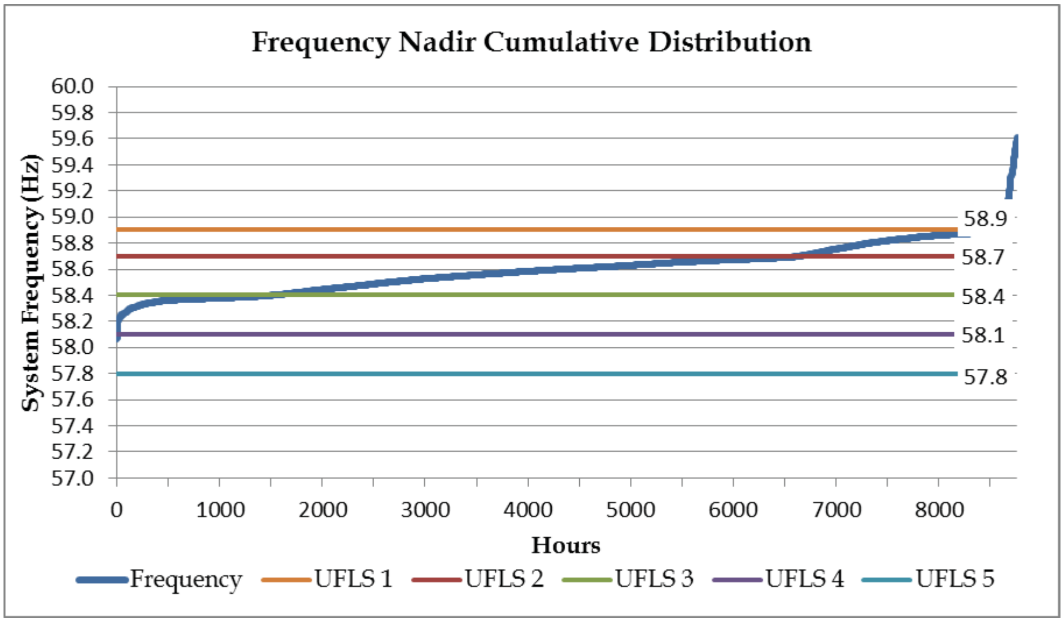

Figure O-119. Frequency Nadir Duration Curve 2019

Figure O-119 shows the frequency nadir duration curve for 2019. The system is at risk of UFLS for 8575 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Thu 3/21/19 Hour 14			DR - AES Trip Boundary Tue 3/19/19 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.8	28.2	26.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	13.3	6.7	3.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	41.6	40.6	17.8
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	31.8	54.4	8.1	38.0	48.2	14.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261	25.0	29.5	1.5			
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.6	57.7	1.8			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	133	0						34			49		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						14			16		
-Na Pua Makani	24	0						12			7		
-CBRE Wind	10	0						2			2		
DG-PV	655	0						437			0		
Station PV	183	0						160			0		
Total Kinetic Energy								4098			3502		
Total Load								1111			585		
Total Thermal Generation								479			537		
Total Renewable Generation								632			49		
Total Generation								1111			585		
Excess Generation								0			0		
Total Up Regulation								356			157		
Total Down Regulation								200			309		
Total FFR2 Capacity								47			26		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		48.4	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		142.3	60.5Hz Output		0.0

Table O-47. Unit Commitment and Dispatch 2019

Table O-47 shows the unit commitment and dispatch for the typical hour (3/21/19, 2:00 PM) and boundary hour (3/19/19, 3:00 AM).

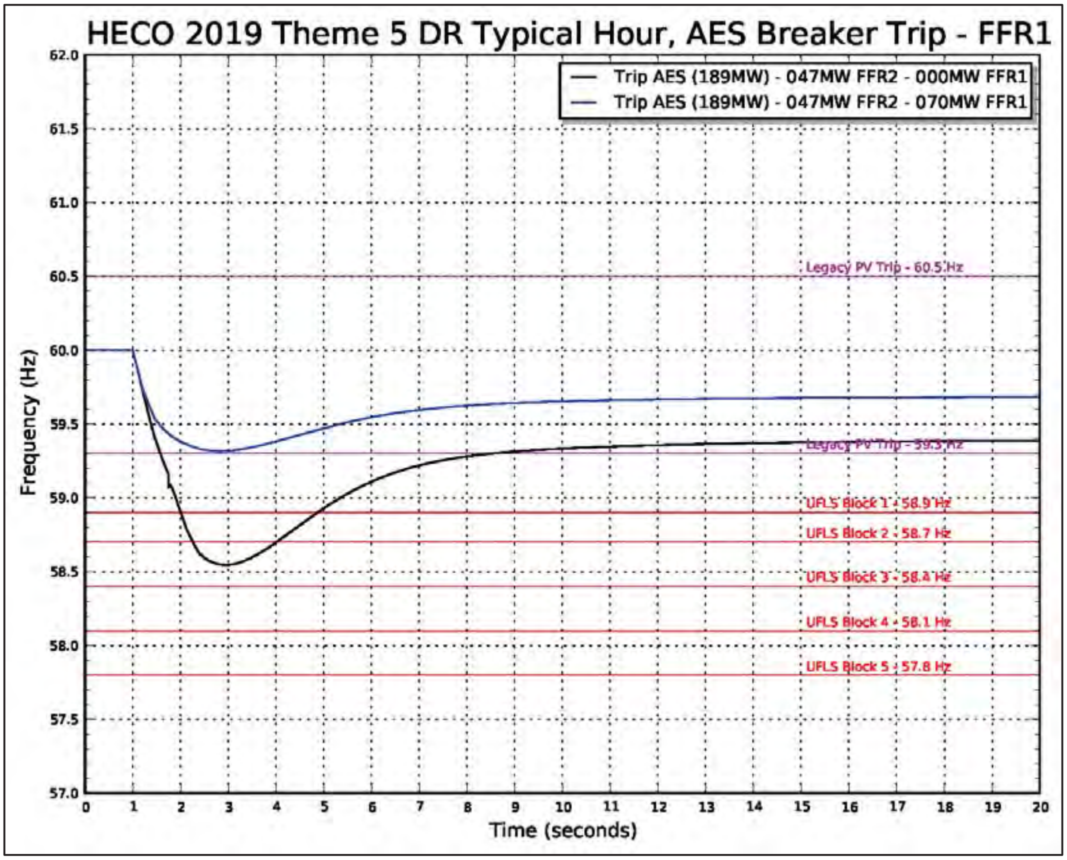

Figure O-120. Frequency Response Profile FFR1 Typical Hour

Figure O-120 shows the frequency response profile for an AES Trip at 189 MW for a typical hour. System kinetic energy is 4098MW-sec, the capacity of legacy PV that will disconnect from the system is 48.4 MW, and the capacity of FFR2 is 47 MW. With no FFR1, the frequency nadir breaches 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 47 MW of FFR2.

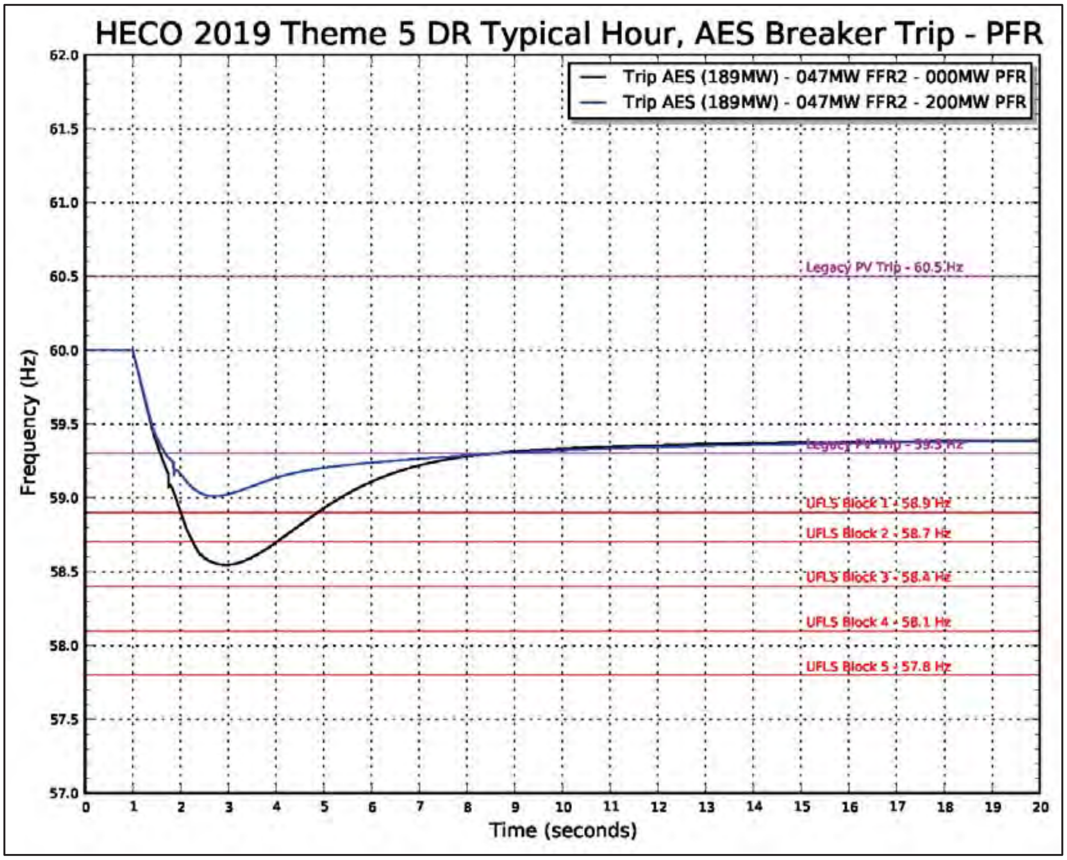

Figure O-121. Frequency Response Profile PFR Typical Hour

Figure O-121 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 47 MW of FFR2 and 356 MW of upward regulation from thermal generation.

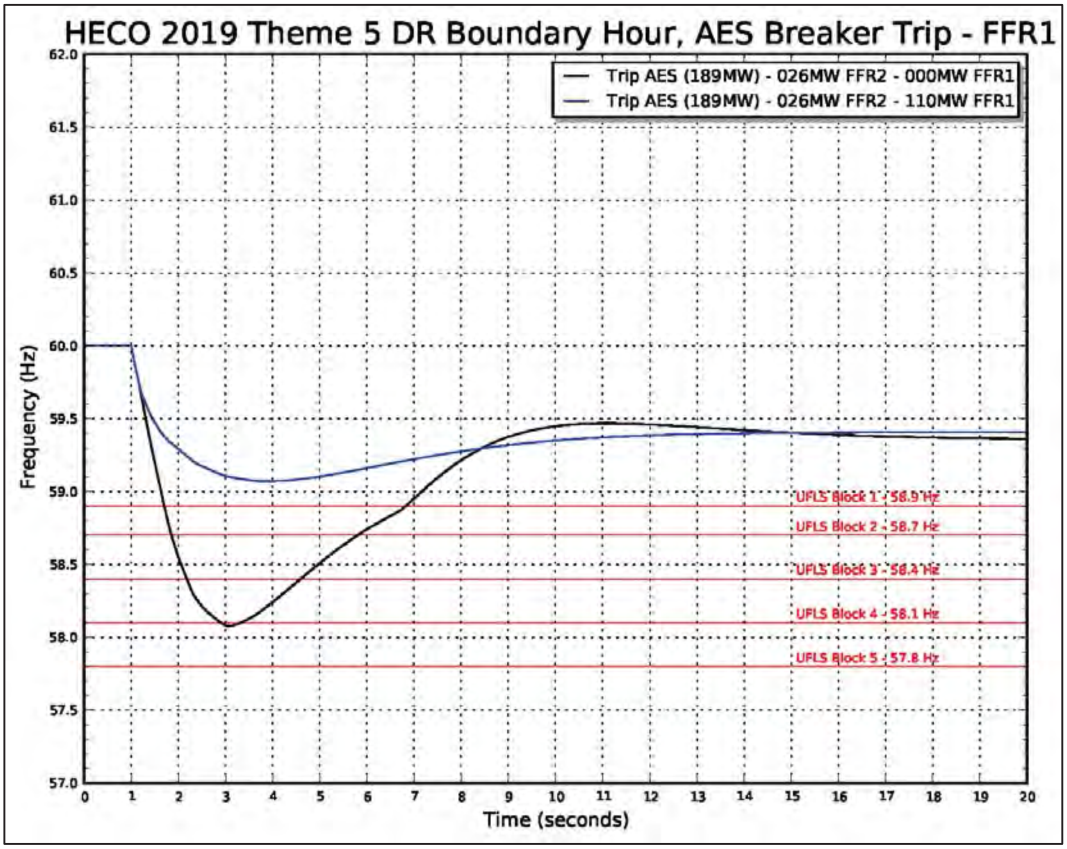

Figure O-122. Frequency Response Profile FFR1 Boundary Hour

Figure O-122 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3502 MW-sec and the capacity of FFR2 is 26 MW. With no FFR1, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW. This is in addition to the 26 MW of FFR2.

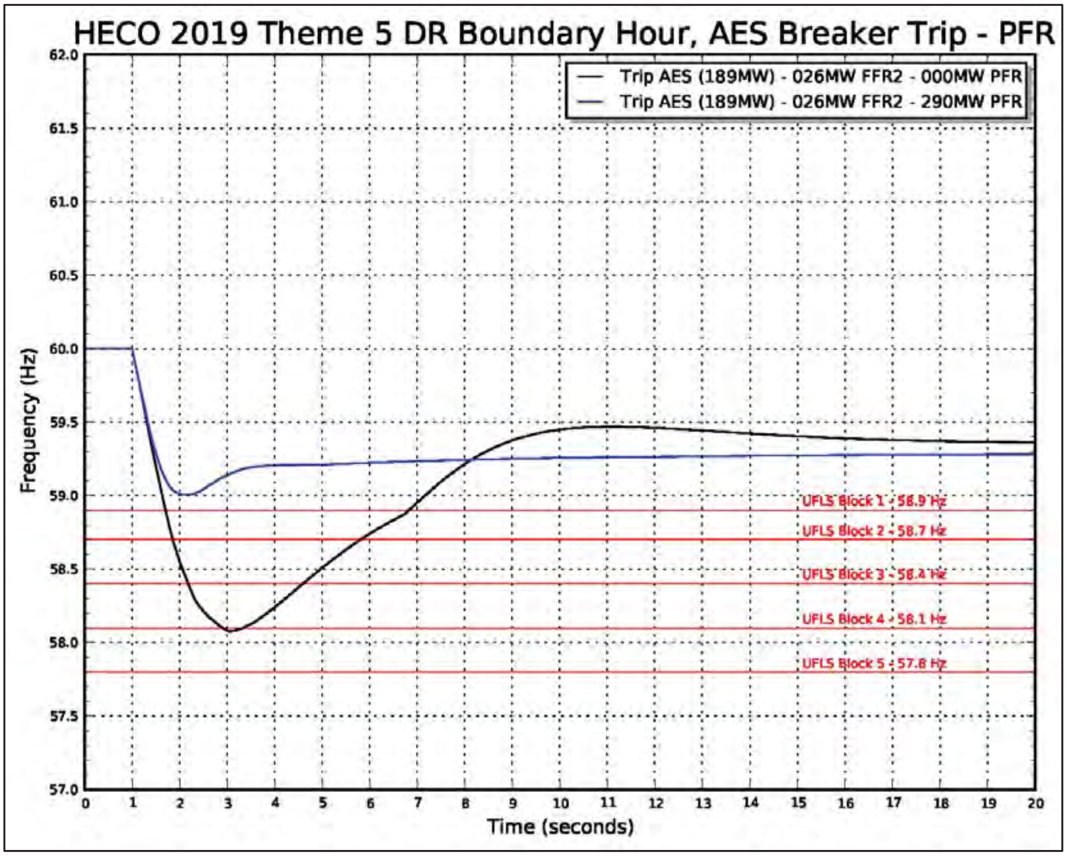

Figure O-123. Frequency Response Profile PFR Boundary Hour

Figure O-123 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 26 MW of FFR2 and 157 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip typical Thu 3/21/19 Hour 14			DR - K5 Trip Boundary Tue 3/19/19 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7			
AES	189.0	63.0			2.57	239.0	615	105.0	84.0	42.0	134.0	55.0	71.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.8	28.2	26.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	13.3	26.7	3.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	31.8	54.4	8.1			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	133	0						34			49		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						14			16		
-Na Pua Makani	24	0						12			7		
-CBRE Wind	10	0						2			2		
DG-PV	655	0						437			0		
Station PV	183	0						160			0		
Total Kinetic Energy								4104			3411		
Total Load								1111			585		
Total Thermal Generation								479			537		
Total Renewable Generation								632			49		
Total Generation								1111			585		
Excess Generation								0			0		
Total Up Regulation								373			123		
Total Down Regulation								226			336		
Total FFR2 Capacity								47			26		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		48.4	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		142.3	60.5Hz Output		0.0

Table O-48. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-48 shows the unit commitment and dispatch for the typical hour (3/21/19, 2:00 PM) and boundary hour (3/19/19, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

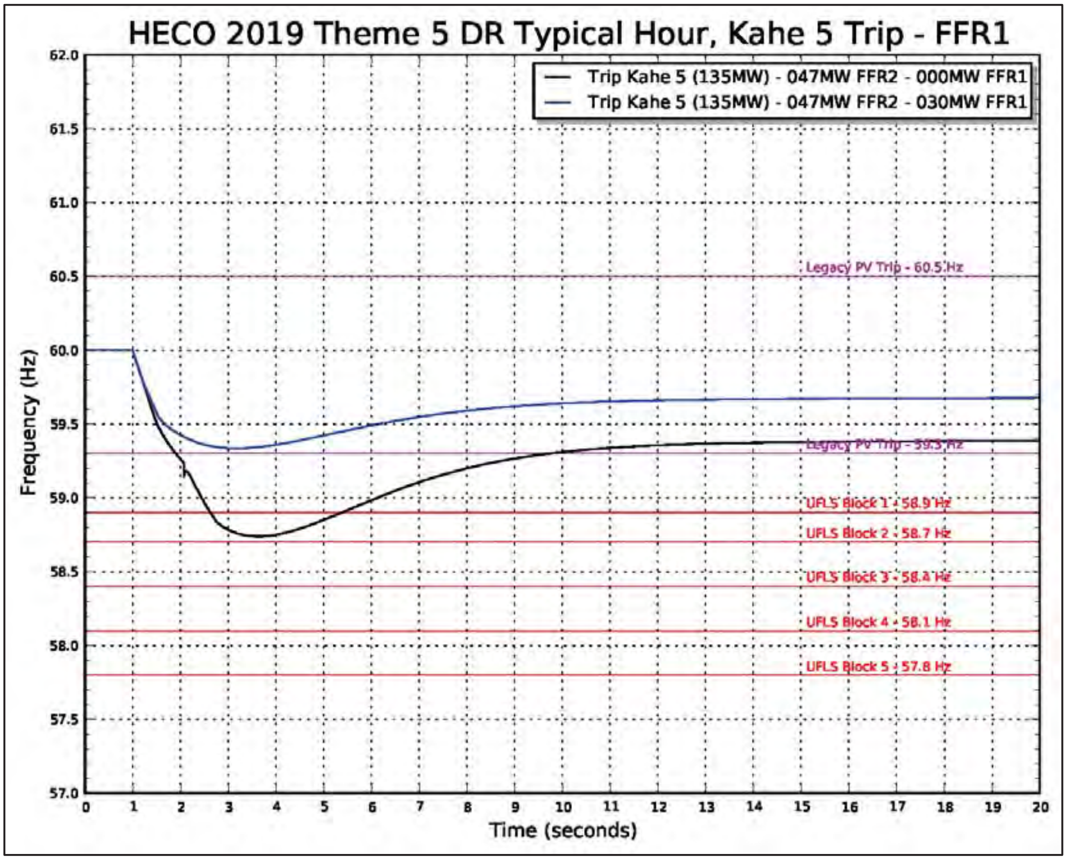

Figure O-124. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-124 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4104 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 48.4 MW, and the capacity of FFR2 is 47 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 30 MW.

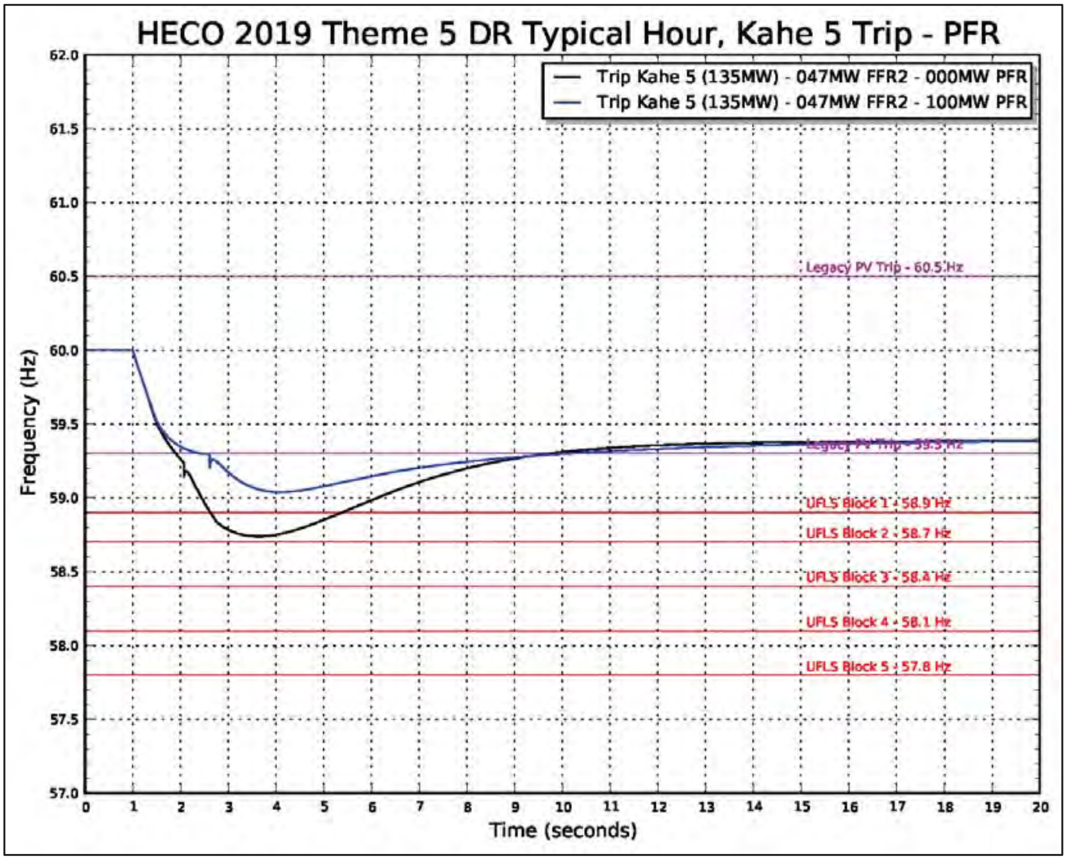

Figure O-125. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-125 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to 47 MW of FFR2 and 373 MW of upward regulation from thermal units.

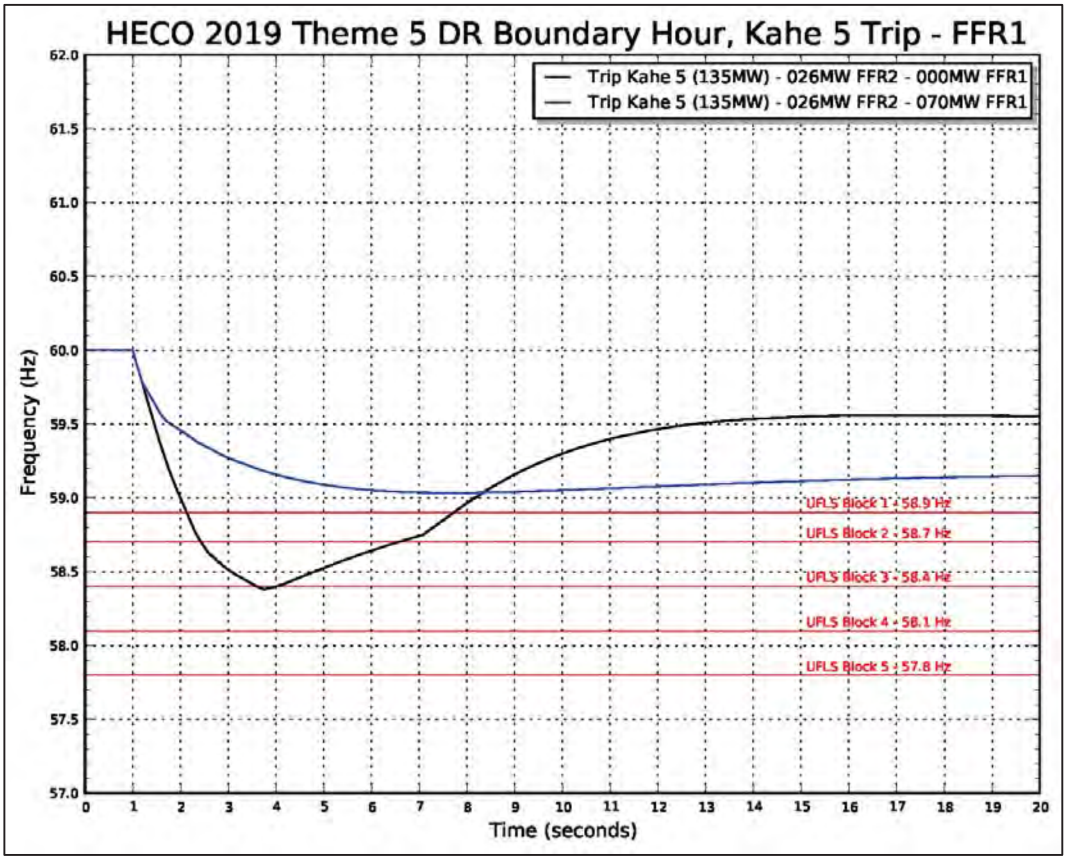

Figure O-126. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-126 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3411 MW-sec and the capacity of FFR2 is 26 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW.

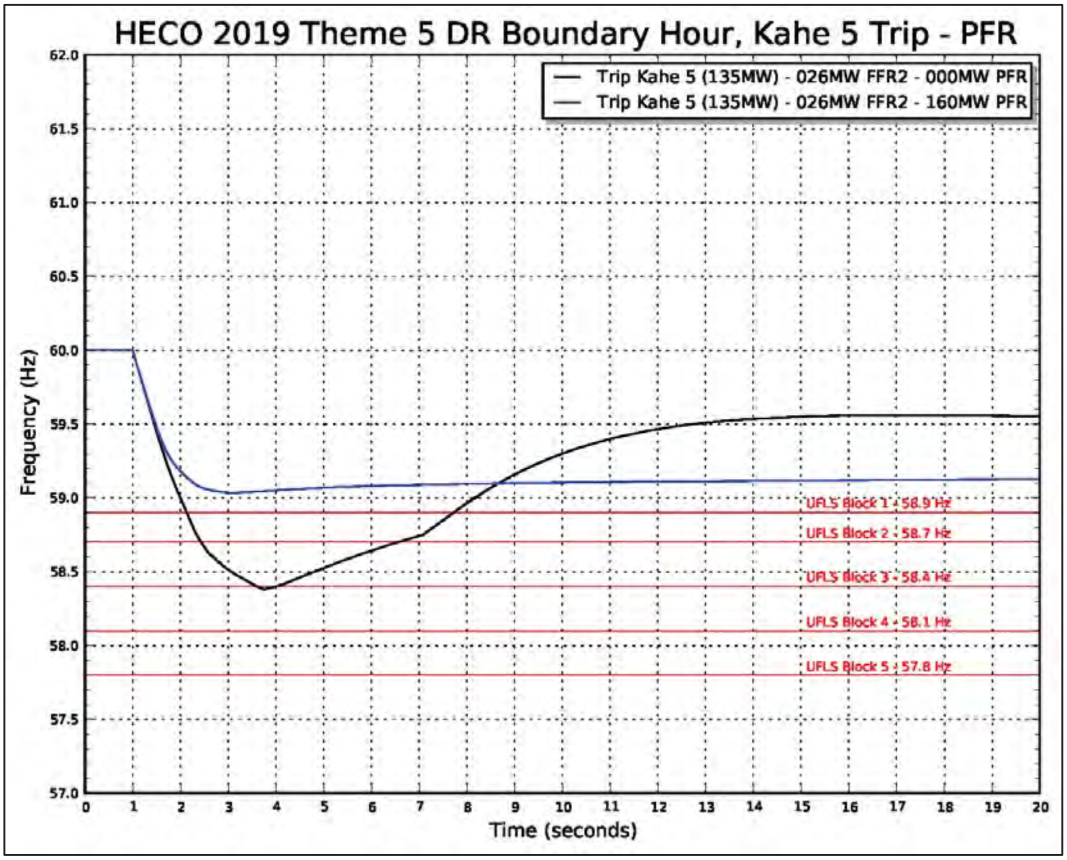

Figure O-127. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-127 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 160 MW. This is in addition to the 26 MW of FFR2 and 123 MW of upward regulation from thermal units.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Sat 6/8/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256	25.0	28.7	1.2
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	133	0						77		
-Kahuku	30	0						21		
-Kawailoa	69	0						31		
-Na Pua Makani	24	0						21		
-CBRE Wind	10	0						4		
DG-PV	655	0						519		
Station PV	183	0						154		
Total Kinetic Energy								3917		
Total Load								1038		
Total Thermal Generation								288		
Total Renewable Generation								750		
Total Generation								1038		
Excess Generation								0		
Total Up Regulation								463		
Total Down Regulation								32		
Total FFR2 Capacity								39		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		57.9
	60.5Hz Capacity			215.9				60.5Hz Output		170.1

Table O-49. Unit Commitment and Dispatch Fault Analysis 2019

Table O-49 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 673 MW.

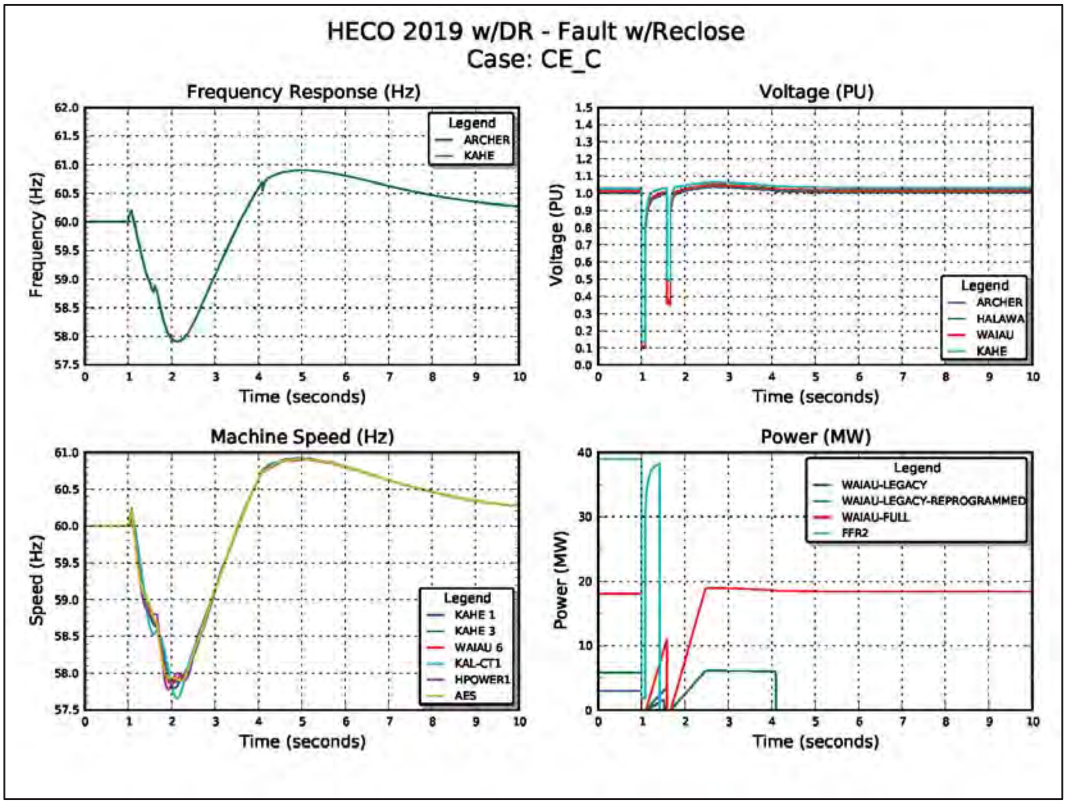

Figure O-128. System Performance for Normally Cleared Fault

Figure O-128 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverter remains connected to the system but output current drops to zero, essentially tripping 673 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, demand response, and four blocks of UFLS is able to stabilize system frequency at 57.9 Hz and avoid system collapse but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system. The under frequency trip setting for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this fault is 57.9 Hz, providing a 0.9 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

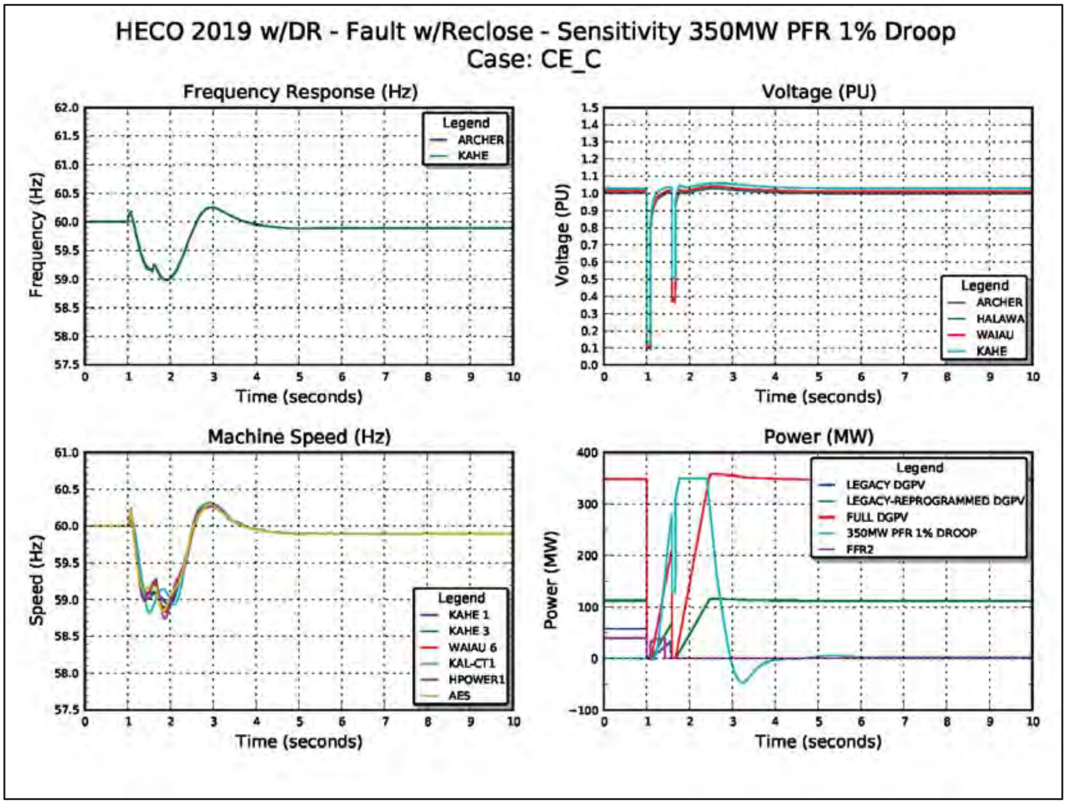

Figure O-129. System Performance Sensitivity Analysis 350 MW PFR

Figure O-129 shows system performance with the addition of 350 MW of PFR at 1% droop response. For the purpose of this analysis, a 350 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 350 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

The breaker failure analysis produced similar results. The system remains stable with significant UFLS and demand response but the stability margin was compromised for each simulation. Further analysis is required to determine an optimal solution to maintain system stability for all circuits.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR-QV Dispatch Thu 7/23/2020 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	70.0	14.0	41.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	31.0	9.0	21.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	70.0	14.0	41.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	33.7	53.6	8.1
Kahe 5	134.6	21.0			4.36	158.8	692	48.9	85.7	27.9
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	163.0	0.0						73.1		
-Kahuku	30.0	0.0						18.9		
-Kawailoa	69.0	0.0						23.5		
-Na Pua Makani	24.0	0.0						18.7		
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	30.0	0.0						9.0		
-Offshore Wind	0.0	0.0								
Total Station PV	362.2	0.0						210.2		
-KS2	5.0	0.0						2.1		
-KREP	5.0	0.0						2.7		
-Waianae	27.6	0.0						18.5		
-Kawailoa PV	49.0	0.0						30.0		
-Mililani 2	14.7	0.0						13.4		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						9.5		
-CBRE PV	15.0	0.0						8.0		
-Future PV	180.0	0.0						95.9		
DG-PV	684.7	0.0						218.4		
Total Kinetic Energy								4269		
Total Load								1069		
Total Thermal Generation								565		
Total Renewable Generation								502		
Total Generation								1067		
Excess Generation								0		
Total Up Regulation								289		
Total Down Regulation								307		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		23.4
	60.5Hz Capacity		215.9					60.5Hz Output		68.9

Table O-50. Unit Commitment and Dispatch 2020 QV Analysis

Table O-50shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Thu 7/23/2020 Hour 17		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.9	33.1	-2.9
HPOWER-2	28.0	-16.0	2.9	25.1	-18.9
AES	99.4	-49.8	27.3	72.1	-77.1
Kalaeloa CT-1	84.5	-35.9	14.5	70.0	-50.4
Kalaeloa ST	42.1	-16.7	14.5	27.6	-31.2
Kalaeloa CT-2	84.5	-35.8	14.5	70.0	-50.3
Kahe 1	68.3	-51.6	27.9	40.4	-79.5
Kahe 2	64.4	-50.3			
Kahe 3	71.2	-21.3	27.9	43.3	-49.2
Kahe 4	64.6	-21.5	27.9	36.7	-49.4
Kahe 5	112.5	-69.0	93.1	19.4	-162.1
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	96.7	-120.3	5.7	91.1	-125.9
-Kahuku	17.9	-17.9	4.2	13.6	-22.1
-Kawailoa	50.0	-74.5	3.2	46.8	-77.7
-Na Pua Makani	16.4	-15.4	-1.8	18.2	-13.6
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	165.6	-165.6	13.4	152.2	-179.0
-KS2	1.6	-1.6	0.2	1.5	-1.8
-KREP	2.0	-2.0	1.6	0.4	-3.6
-Waianae	14.5	-14.5	1.4	13.1	-15.9
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	0.0	10.7	-10.7
-Waiawa	32.9	-32.9	0.5	32.4	-33.3
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	56.2	-56.2	7.9	48.3	-64.1
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			253.8		
Total Renewable MVAR Generation			19.0		
Total Cap Bank MVAR			185.6		
Charging MVAR			77.3		
Total MVAR Supply			535.7		
Total MVAR Load			348.1		
Total MVAR Losses			187.8		
Excess MVAR Generation			-0.1		
Total MVAR Supply Capability				680.7	
Total MVAR Absorb Capability					-876.3

Table O-51. MVAR Capability 2020 QV Analysis

Table O-51 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-52. N-2 Contingencies 2020 QV Analysis

Table O-52 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

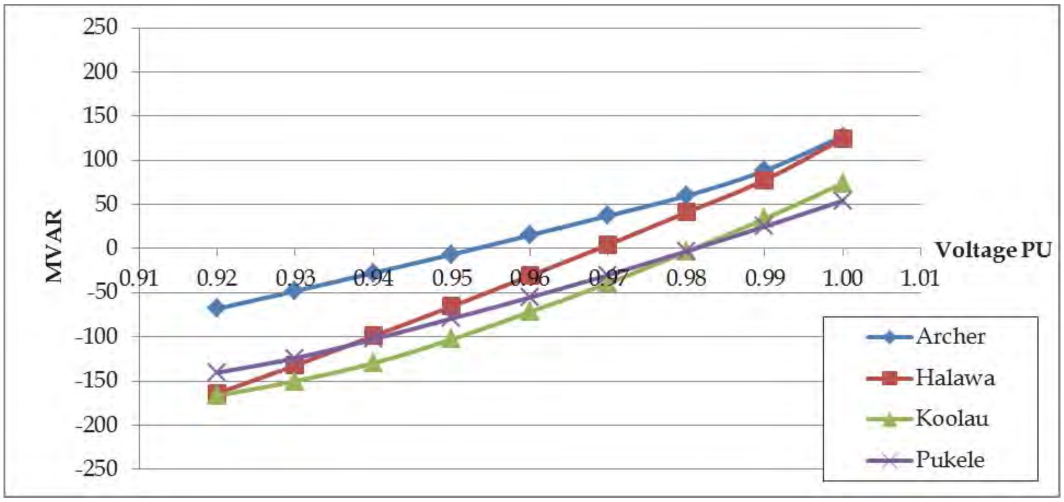

Figure O-130. QV Curves 2020

Figure O-130 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	127	154	88	244	60	135	37	135	15	135	-7	135	-28	135	-48	135	-68
120	Halawa	125	125	154	77	154	41	154	4	154	-31	154	-66	154	-99	154	-132	154	-164
150	Koolau	125	74	154	34	154	-4	125	-39	125	-72	125	-103	125	-130	316	-150	316	-167
170	Pukele	125	54	154	25	154	-3	125	-30	125	-55	125	-79	125	-103	125	-124	316	-140

Table O-53. Summary of Results 2020 QV Analysis

Table O-53 shows the results of the 2020 QV analysis. The unit commitment and dispatch is able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

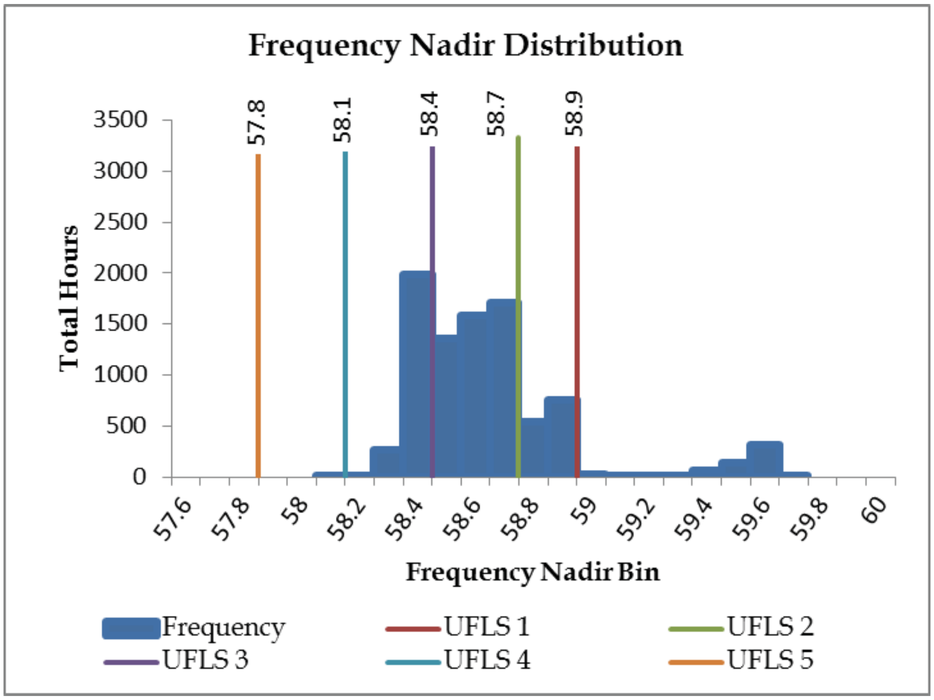

Figure O-131. Frequency Nadir Histogram 2020

Figure O-131 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1980 hours was 11:00 AM on Friday, January 31. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 3 hours was 3:00 AM on Thursday, January 30. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

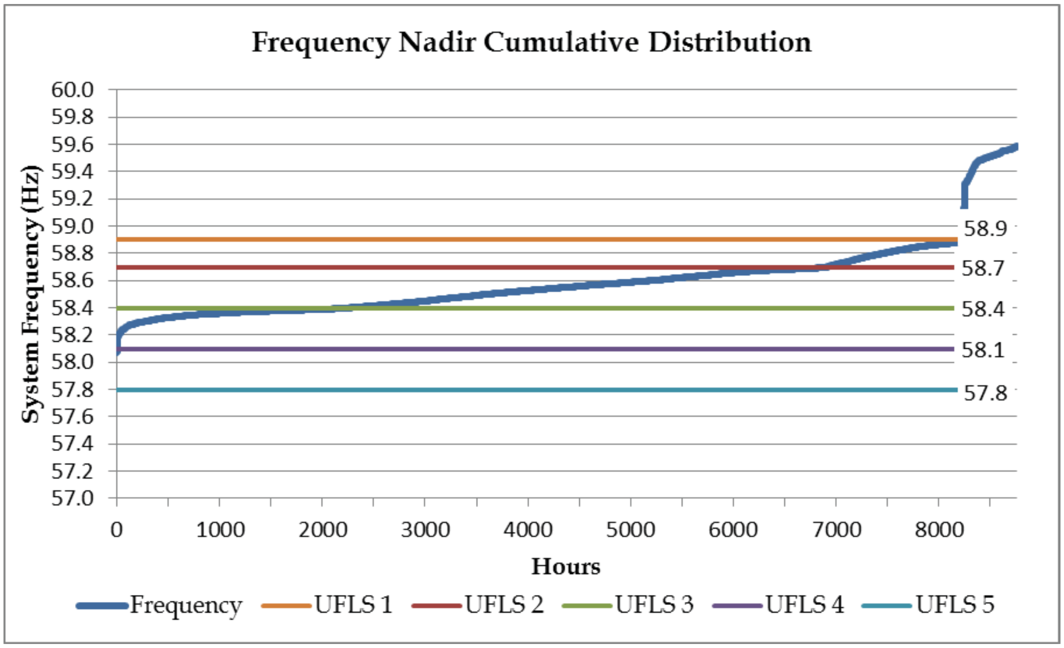

Figure O-132. Frequency Nadir Duration Curve 2020

Figure O-132 shows the frequency nadir duration curve for 2020. The system is at risk of UFLS for 8188 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Fri 1/31/20 Hour 11			DR - AES Trip Boundary Thu 1/30/20 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.7	11.3	43.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	17.3	2.7	7.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	32.1	50.1	8.3
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	28.3	57.9	4.6	45.4	40.8	21.7
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4	31.7	53.6	8.1
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.0	58.3	1.2			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	25.0	61.2	0.9			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	163	0						17			55		
-Kahuku	30	0						1			22		
-Kawailoa	69	0						4			26		
-Na Pua Makani	24	0						0			0		
-CBRE Wind	10	0						3			2		
DG-PV	685	0						367			0		
Station PV	363	0						272			0		
Total Kinetic Energy								3838			3433		
Total Load								1109			597		
Total Thermal Generation								453			541		
Total Renewable Generation								657			55		
Total Generation								1109			597		
Excess Generation								0			0		
Total Up Regulation								332			156		
Total Down Regulation								197			314		
Total FFR2 Capacity								49			35		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		114.4	60.5Hz Output		0.0

Table O-54. Unit Commitment and Dispatch 2020

Table O-54 shows the unit commitment and dispatch for the typical hour (1/31/20, 11:00 AM) and boundary hour (1/30/20, 3:00 AM).

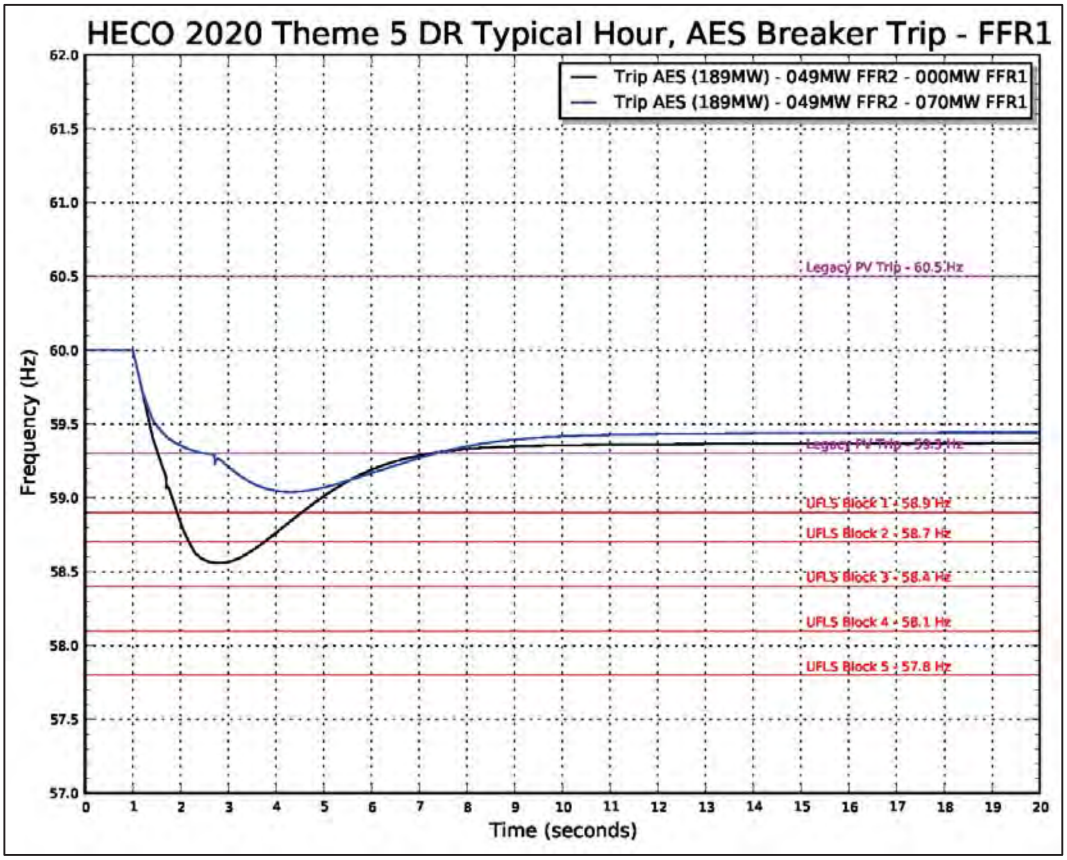

Figure O-133. Frequency Response Profile FFR1 Typical Hour

Figure O-133 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3838 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 39 MW, and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 49 MW of FFR2.

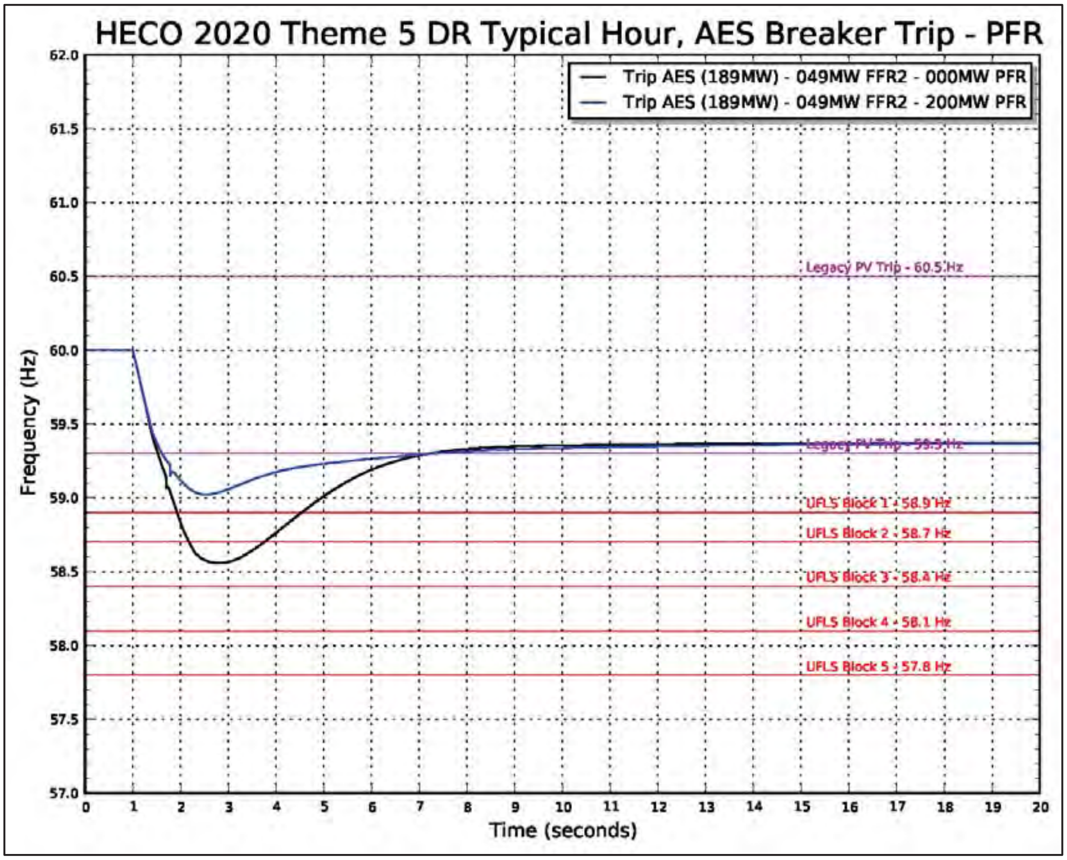

Figure O-134. Frequency Response Profile PFR Typical Hour

Figure O-134 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 49 MW of FFR2 and 332 MW of upward regulation from thermal generation.

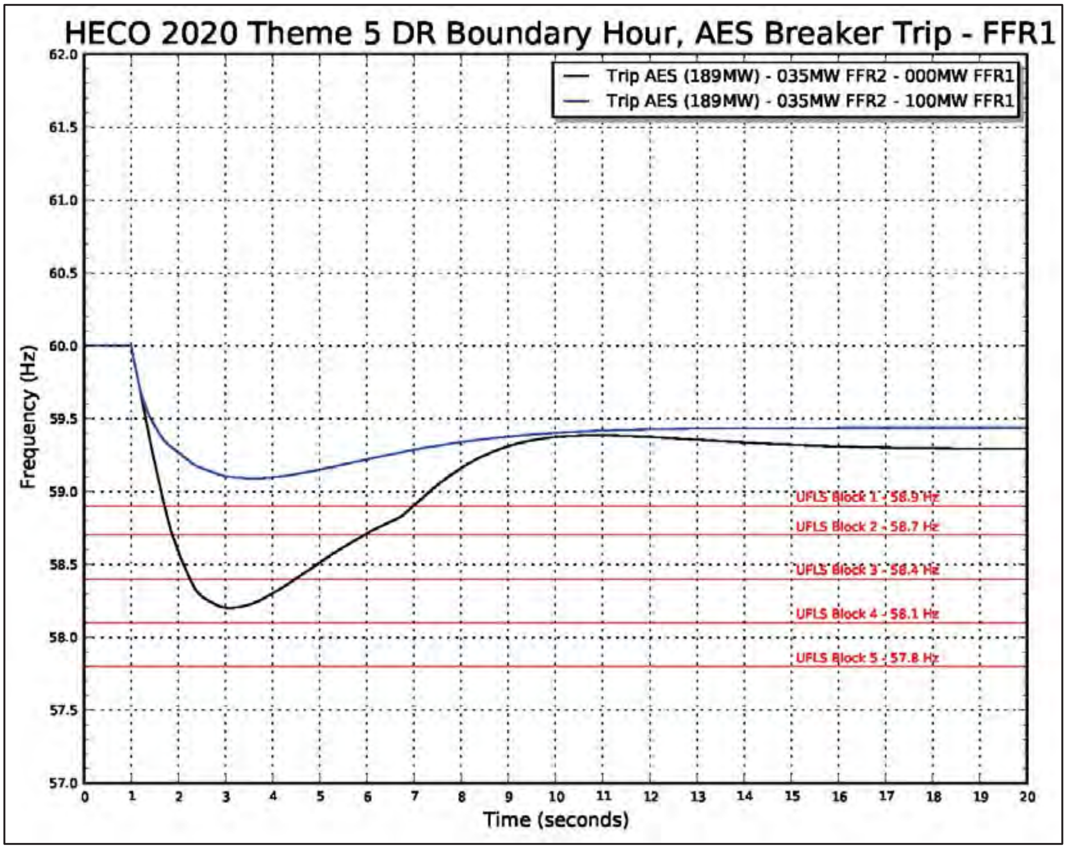

Figure O-135. Frequency Response Profile FFR1 Boundary Hour

Figure O-135 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3433 MW-sec and the capacity of FFR2 is 35 MW. With no FFR1, the frequency nadir breaches 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 35 MW of FFR2.

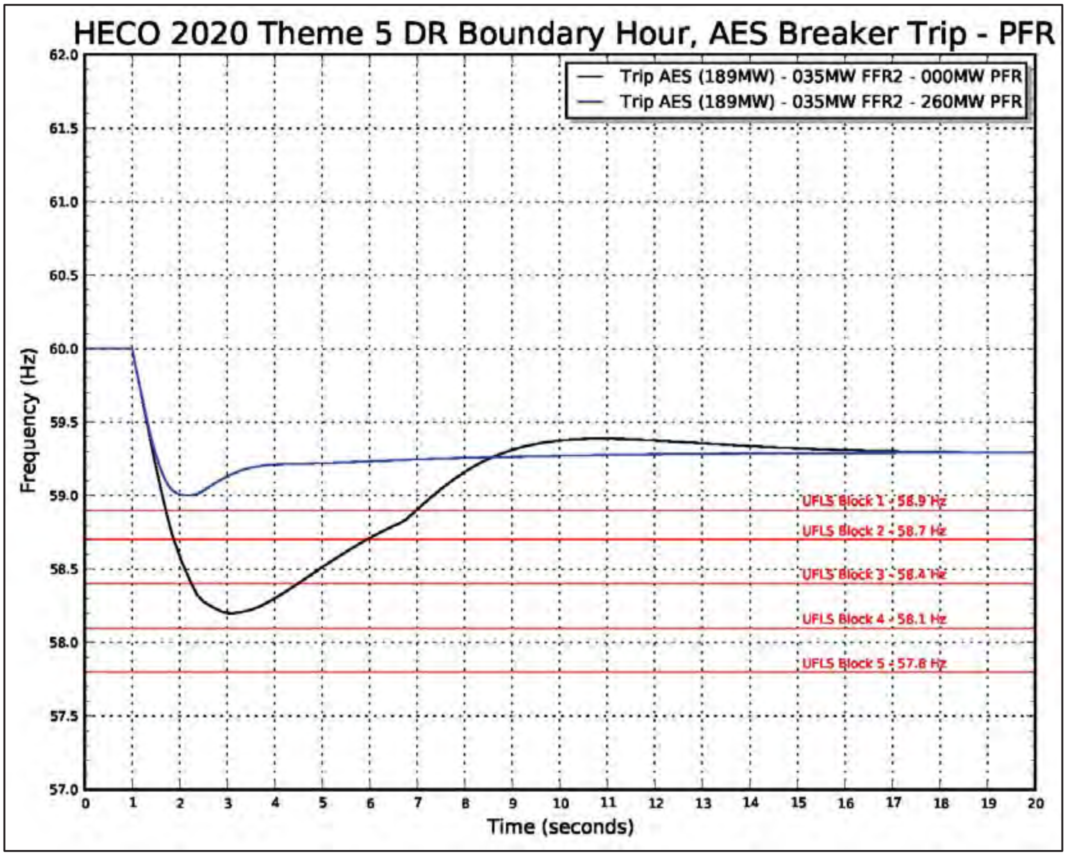

Figure O-136. Frequency Response Profile PFR Typical Hour

Figure O-136 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 35 MW of FFR2 and 156 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 1/31/20 Hour 11			DR - K5 Trip Boundary Thu 1/30/20 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	104.0	85.0	41.0	131.0	58.0	68.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.7	11.3	43.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	17.3	2.7	7.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	32.1	50.1	8.3
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	28.3	57.9	4.6			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	163	0						17			55		
-Kahuku	30	0						1			22		
-Kawailoa	69	0						4			26		
-Na Pua Makani	24	0						0			0		
-CBRE Wind	10	0						3			2		
DG-PV	685	0						367			0		
Station PV	363	0						272			0		
Total Kinetic Energy								3678			3411		
Total Load								1109			597		
Total Thermal Generation								452			541		
Total Renewable Generation								657			55		
Total Generation								1109			596		
Excess Generation								0			0		
Total Up Regulation								298			119		
Total Down Regulation								223			340		
Total FFR2 Capacity								49			35		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		114.4	60.5Hz Output		0.0

Table O-55. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-55 shows the unit commitment and dispatch for the typical hour (1/31/20, 11:00 AM) and boundary hour (1/30/20, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

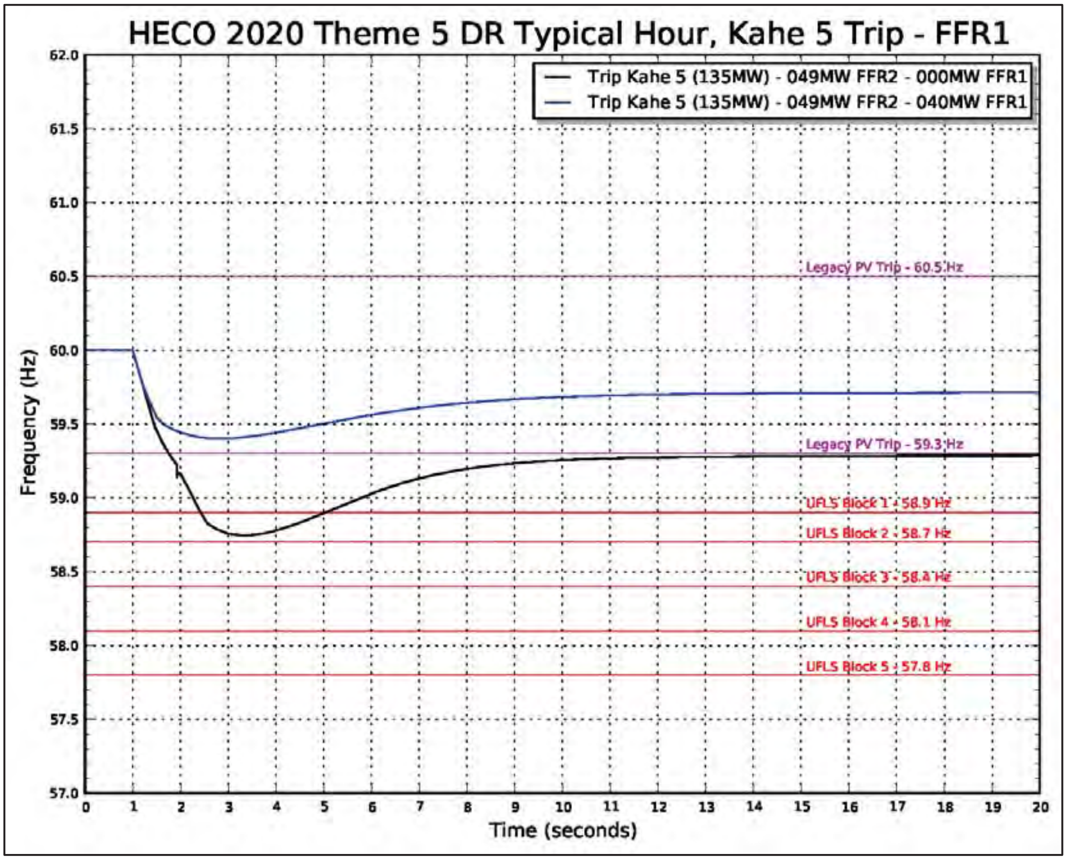

Figure O-137. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-137 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3678 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 39 MW, and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 49 MW of FFR2.

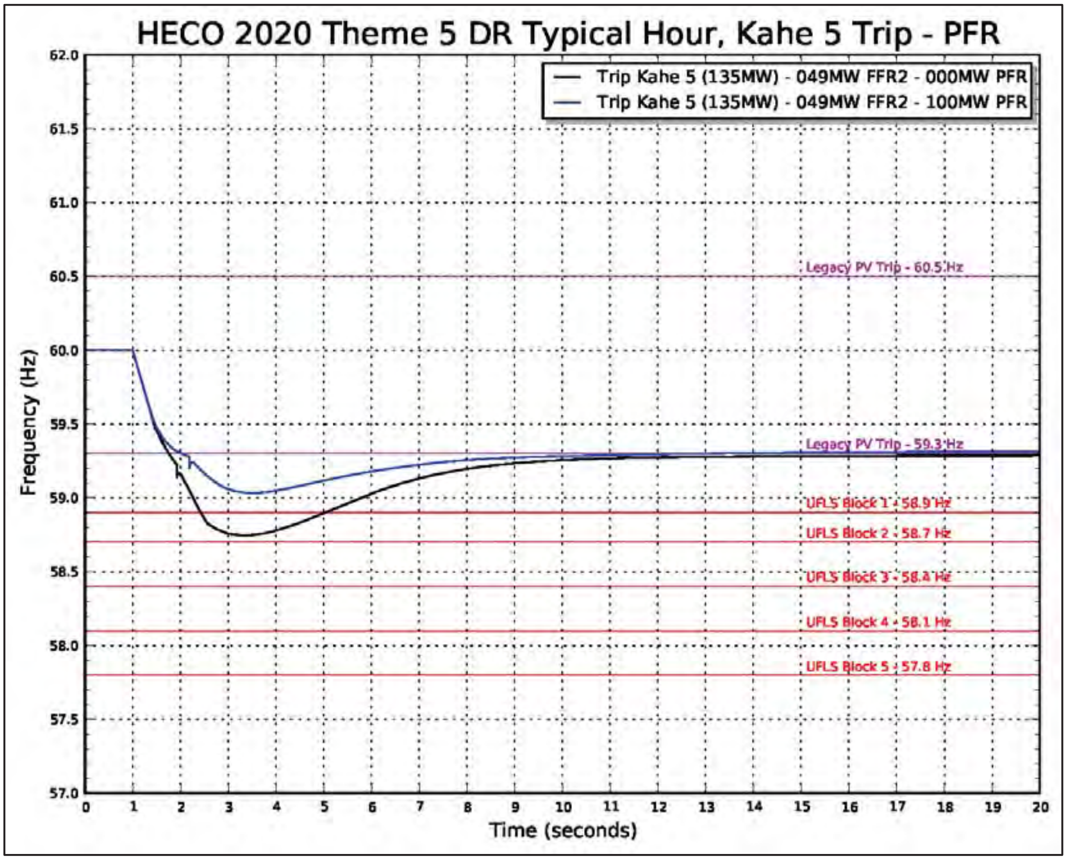

Figure O-138. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-138 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 49 MW of FFR2 and 298 MW of upward regulation from thermal generation.

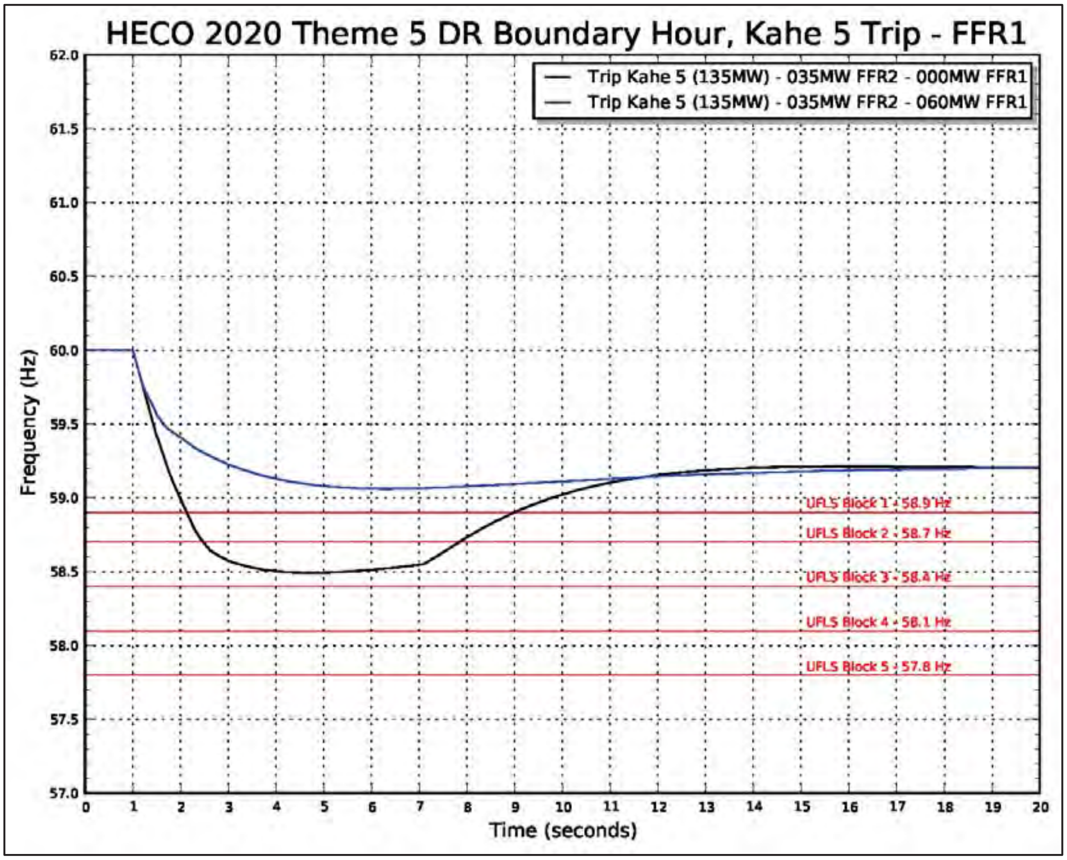

Figure O-139. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-139 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3411 MW-sec and the capacity of FFR2 is 35 MW. With no FFR, the frequency nadir is 58.5 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 35 MW of FFR2.

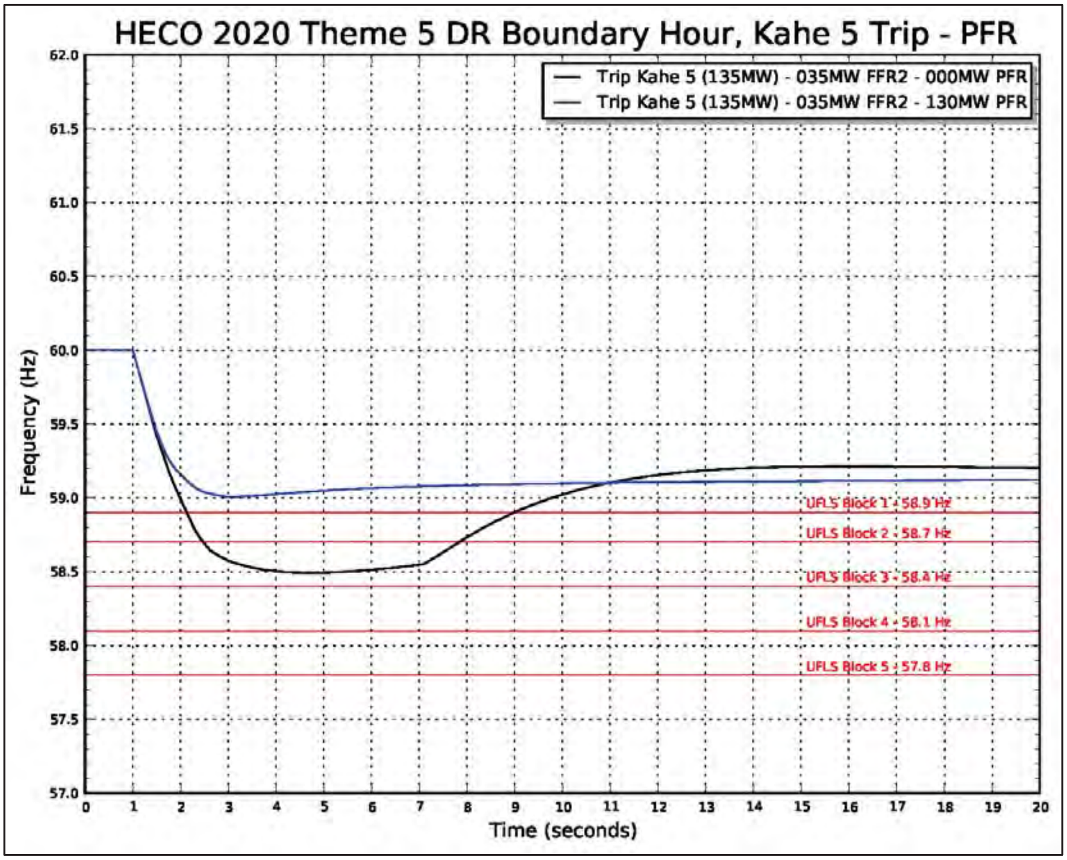

Figure O-140. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-140 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 35 MW FFR2 and 119 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Wed 5/27/20 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	28.7	17.3	3.7
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.5	125.5	0.5
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Total Wind	163	0						53		
-Kahuku	30	0						11		
-Kawailoa	69	0						17		
-Na Pua Makani	24	0						17		
-CBRE Wind	10	0						2		
DG-PV	685	0						542		
Station PV	363	0						346		
Total Kinetic Energy									3411	
Total Load									1208	
Total Thermal Generation									267	
Total Renewable Generation									941	
Total Generation									1208	
Excess Generation									0	
Total Up Regulation									430	
Total Down Regulation									35	
Total FFR2 Capacity									55	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		57.7
	60.5Hz Capacity			215.9				60.5Hz Output		169.5

Table O-56. Unit Commitment and Dispatch Fault Analysis 2020

Table O-56 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 888 MW and the capacity of demand response is 55 MW.

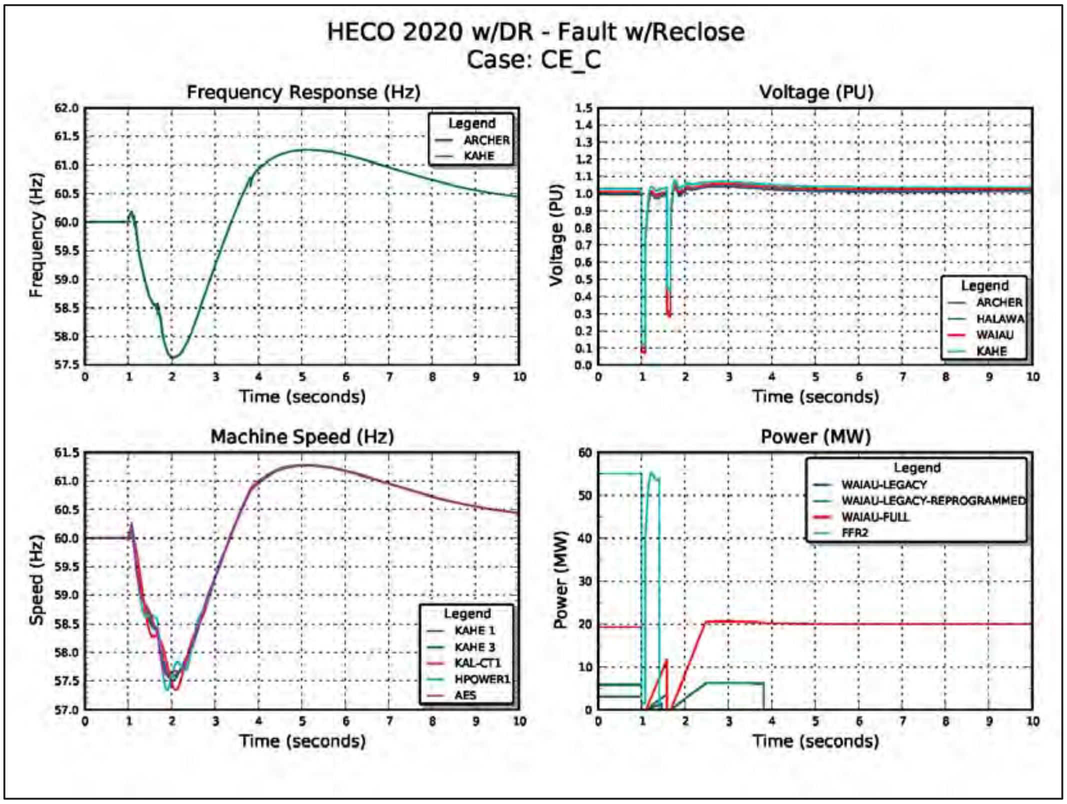

Figure O-141. System Performance for Normally Cleared Fault

Figure O-141 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverter remains connected to the system but its output current drops to zero, essentially tripping 888 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, demand response, and five blocks of UFLS is able to stabilize system frequency at 57.6 Hz but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Waiau is indicative of DG-PV performance across the entire system. The under frequency trip setting for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this fault is 57.6 Hz, providing a 0.6 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

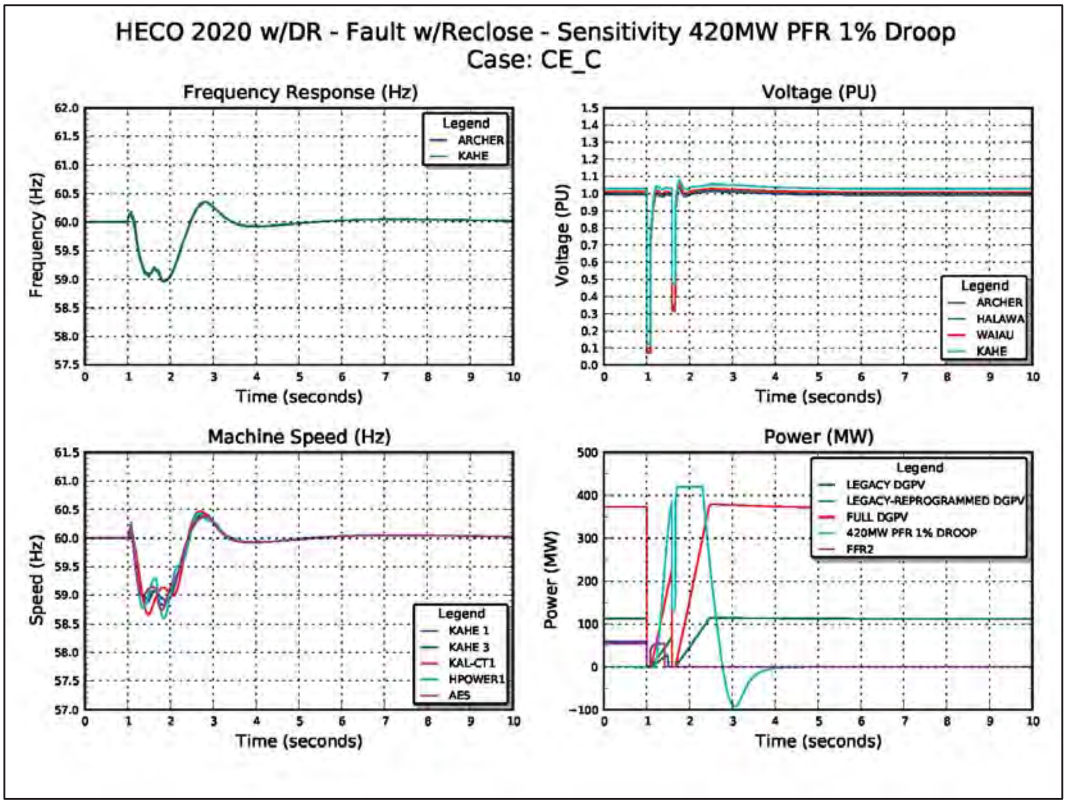

Figure O-142. System Performance Sensitivity Analysis 420 MW PFR

Figure O-142 shows system performance with the addition of 420 MW of PFR at 1% droop response. For the purpose of this analysis, a 420 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 420 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

The breaker failure analysis produced similar results. The system remains stable with significant UFLS and demand response but the stability margin was compromised for each simulation. Further analysis is required to determine an optimal solution to bring the system into compliance with TPL-001 and increase the stability margin of the system.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR - QV Dispatch Sun 9/19/2021 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.0	29.0	26.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	19.9	20.1	9.9
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	55.0	29.0	26.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	27.0	58.3	3.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	163.0	0.0						52.2		
-Kahuku	30.0	0.0						8.7		
-Kawailoa	69.0	0.0						14.5		
-Na Pua Makani	24.0	0.0						17.0		
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	30.0	0.0						9.0		
-Offshore Wind	0.0	0.0								
Total Station PV	462.2	0.0						236.3		
-KS2	5.0	0.0						3.4		
-KREP	5.0	0.0						2.7		
-Waianae	27.6	0.0						21.3		
-Kawailoa PV	49.0	0.0						37.7		
-Mililani 2	14.7	0.0						11.3		
-Waiawa	45.9	0.0						35.3		
-Westloch	20.0	0.0						14.3		
-CBRE PV	15.0	0.0						5.6		
-Future PV	280.0	0.0						104.7		
DG-PV	712.0	0.0						393.6		
Total Kinetic Energy								4003		
Total Load								1172		
Total Thermal Generation								489		
Total Renewable Generation								682		
Total Generation								1172		
Excess Generation								0		
Total Up Regulation								312		
Total Down Regulation								228		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		40.6
	60.5Hz Capacity			215.9				60.5Hz Output		119.3

Table O-57. Unit Commitment and Dispatch 2021 QV Analysis

Table O-57 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Sun 9/19/2021 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.2	33.8	-2.2
HPOWER-2	28.0	-16.0	2.2	25.8	-18.2
AES	99.4	-49.8	29.7	69.7	-79.5
Kalaeloa CT-1	84.5	-35.9	14.9	69.6	-50.8
Kalaeloa ST	42.1	-16.7	14.9	27.2	-31.6
Kalaeloa CT-2	84.5	-35.8	14.9	69.6	-50.7
Kahe 1	68.3	-51.6	43.1	25.2	-94.7
Kahe 2	68.3	-51.6	43.1	25.2	-94.7
Kahe 3	74.2	-25.0	43.1	31.1	-68.1
Kahe 4	66.5	-23.1	64.3	2.2	-87.4
Kahe 5	112.5	-69.0			
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	96.7	-120.3	7.4	89.3	-127.7
-Kahuku	17.9	-17.9	4.4	13.4	-22.3
-Kawailoa	50.0	-74.5	4.2	45.8	-78.7
-Na Pua Makani	16.4	-15.4	-1.2	17.6	-14.3
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	196.8	-196.8	16.5	180.3	-213.4
-KS2	1.6	-1.6	0.5	1.2	-2.1
-KREP	2.0	-2.0	1.8	0.2	-3.8
-Waianae	14.5	-14.5	2.2	12.4	-16.7
-Kawailoa PV	36.8	-36.8	0.0	36.7	-36.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.5
-Waiawa	32.9	-32.9	1.2	31.7	-34.0
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	87.4	-87.4	8.7	78.7	-96.1
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			272.4		
Total Renewable MVAR Generation			24.0		
Total Cap Bank MVAR			184.0		
Charging MVAR			76.9		
Total MVAR Supply			557.2		
Total MVAR Load			382.1		
Total MVAR Losses			175.6		
Excess MVAR Generation			-0.5		
Total MVAR Supply Capability				649.1	
Total MVAR Absorb Capability					-918.9

Table O-58. MVAR Capability 2021 QV Analysis

Table O-58 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-59. N-2 Contingencies 2021 QV Analysis

Table O-59 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

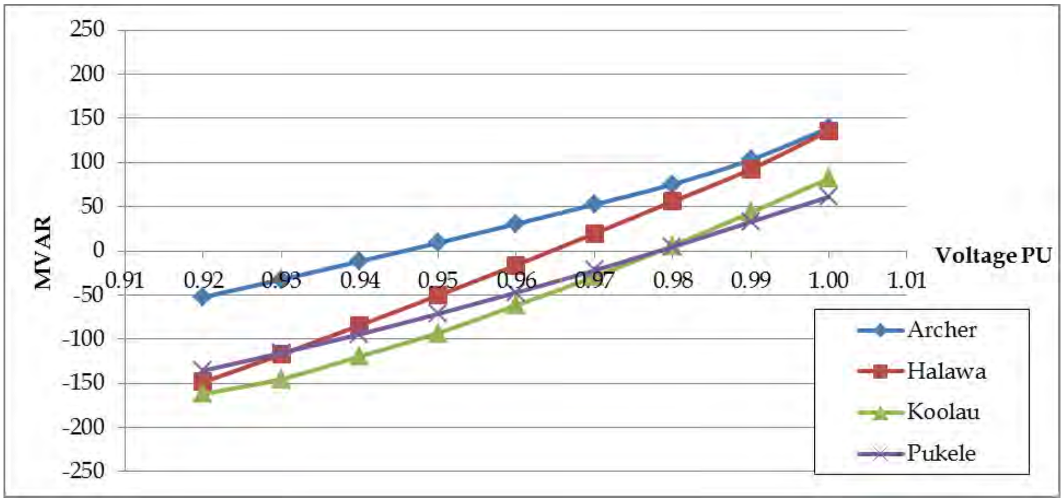

Figure O-143. QV Curves 2021

Figure O-143 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation requires an additional 9 MVAR to maintain system voltage at 0.95 PU for an N-2 contingency. The system has 649 MVAR of reactive power reserve capacity but all of these resources are on the west side of the island, far from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	139	154	103	244	75	135	52	135	31	135	9	135	-12	135	-32	135	-52
120	Halawa	125	136	154	93	154	56	154	20	154	-16	154	-50	154	-84	154	-117	154	-149
150	Koolau	154	82	154	43	154	6	125	-29	125	-62	125	-93	125	-119	316	-145	316	-162
170	Pukele	154	61	154	33	154	4	125	-22	125	-47	125	-71	125	-94	125	-116	125	-136

Table O-60. Results 2021 QV Analysis

Table O-60 shows the results of the 2021 QV analysis. Archer Substation requires an additional 9 MVARS to meet the reactive power requirements under N-2 contingencies.

To mitigate the reactive power shortfall at Archer Substation, a sensitivity analysis was performed with Honolulu 8 and 9 synchronous condensers added to the system.

Unit	Unit Ratings		DR - QV MVAR Capability Sun 9/19/2021 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.2	33.8	-2.2
HPOWER-2	28.0	-16.0	2.2	25.8	-18.2
AES	99.4	-49.8	26.0	73.4	-75.8
Kalaeloa CT-1	84.5	-35.9	13.1	71.4	-49.0
Kalaeloa ST	42.1	-16.7	13.1	29.0	-29.8
Kalaeloa CT-2	84.5	-35.8	13.1	71.4	-48.9
Kahe 1	68.3	-51.6	34.1	34.2	-85.7
Kahe 2	68.3	-51.6	34.1	34.2	-85.7
Kahe 3	74.2	-25.0	34.1	40.1	-59.1
Kahe 4	66.7	-23.2	64.3	2.4	-87.5
Kahe 5	112.5	-69.0			
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	16.1	34.9	-49.1
Hon 9 (Sync Cond)	51.0	-33.0	16.1	34.9	-49.1
Total Wind	96.7	-120.3	5.4	91.4	-125.7
-Kahuku	17.9	-17.9	4.2	13.7	-22.0
-Kawailoa	50.0	-74.5	3.5	46.5	-78.0
-Na Pua Makani	16.4	-15.4	-2.3	18.7	-13.1
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	196.8	-196.8	15.1	181.7	-212.0
-KS2	1.6	-1.6	0.5	1.2	-2.1
-KREP	2.0	-2.0	1.8	0.2	-3.8
-Waianae	14.5	-14.5	2.2	12.4	-16.7
-Kawailoa PV	36.8	-36.8	0.0	36.7	-36.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	0.8	32.0	-33.7
-Westloch	6.3	-6.3	2.9	3.4	-9.1
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	87.4	-87.4	7.3	80.1	-94.7
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			268.3		
Total Renewable MVAR Generation			20.5		
Total Cap Bank MVAR			185.5		
Charging MVAR			77.6		
Total MVAR Supply			551.9		
Total MVAR Load			382.1		
Total MVAR Losses			169.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				758.8	
Total MVAR Absorb Capability					-977.5

Table O-61. MVAR Capability 2021 QV Sensitivity Analysis

Table O-61 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch with the addition of the Honolulu 8 and 9 synchronous condensers.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe_Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-62. N-2 Contingencies 2021 Sensitivity Analysis

Table O-62 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

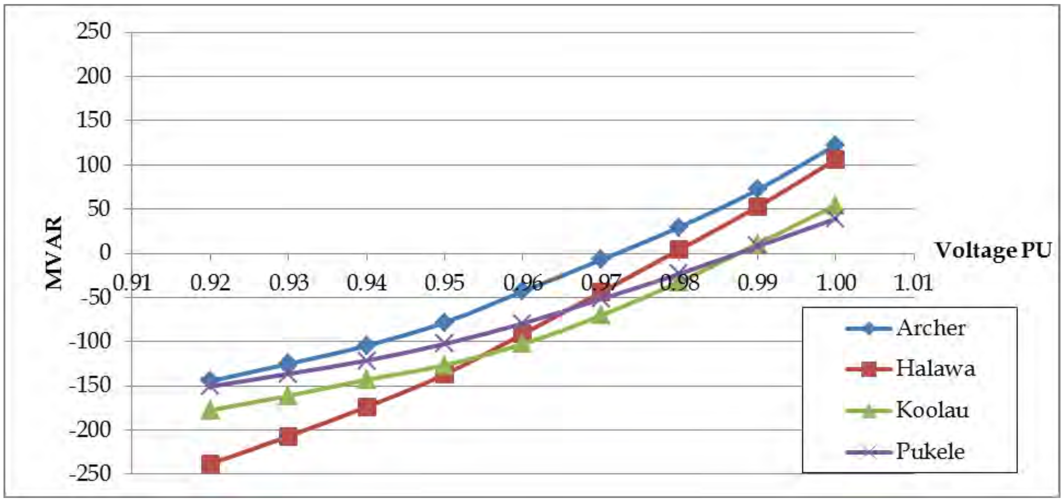

Figure O-144. QV Curves with H8 & H9 Synchronous Condensers

Figure O-144 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation is able to maintain bus voltage at 0.95 PU with the additional 60 MVAR of reactive power from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	123	154	72	244	30	135	-7	135	-43	135	-78	135	-104	135	-125	135	-145
120	Halawa	125	106	154	53	154	4	154	-44	154	-91	154	-137	154	-174	154	-207	154	-238
150	Koolau	125	54	125	11	125	-32	125	-70	316	-102	203	-126	203	-143	203	-161	203	-177
170	Pukele	125	39	125	8	125	-23	125	-52	125	-79	316	-102	316	-121	203	-136	203	-151

Table O-63. Summary of Results 2021 QV Mitigation Analysis

Table O-63 shows the results of the QV analysis with the Honolulu 8 and 9 synchronous condensers. The unit commitment and dispatch in conjunction with the Honolulu 8 and 9 synchronous condensers are able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

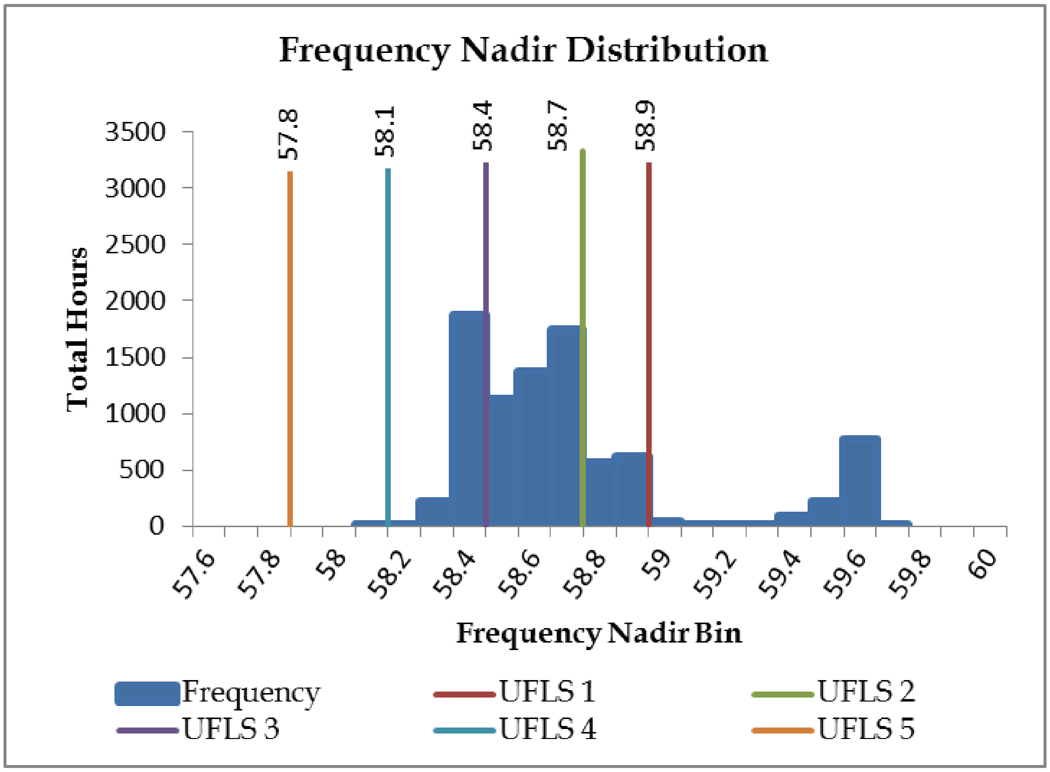

Figure O-145. Frequency Nadir Histogram 2021

Figure O-145 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1871 hours was 10:00 AM on Tuesday, February 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 18 hours was 3:00 AM on Sunday, March 14. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

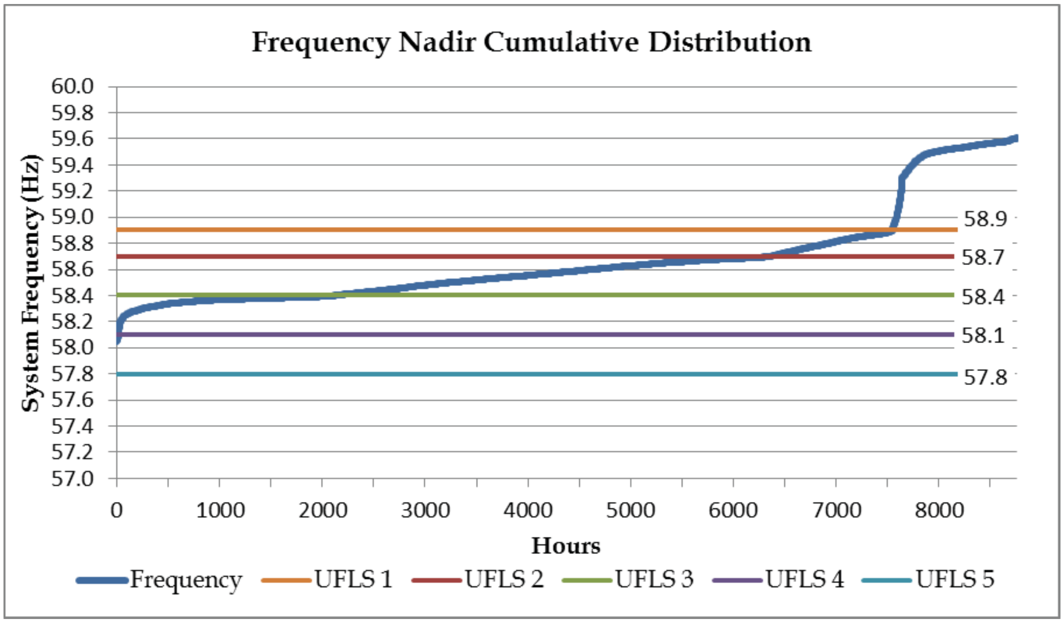

Figure O-146. Frequency Nadir Duration Curve 2021

Figure O-146 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for 7546 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Tue 2/23/21 Hour 10			DR - AES Trip Boundary Sun 3/14/21 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	62.7	21.3	33.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	14.9	5.1	4.9	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	32.1	54.1	8.4			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4	41.3	44.0	17.7
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261				25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	25.0	61.2	0.9	25.0	61.2	0.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						30			53		
-Kahuku	30	0						1			11		
-Kawailoa	69	0						12			13		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						4			2		
DG-PV	712	0						321			0		
Station PV	463	0						272			0		
Total Kinetic Energy									4087			3586	
Total Load									1066			576	
Total Thermal Generation									444			523	
Total Renewable Generation									622			53	
Total Generation									1066			576	
Excess Generation									0			0	
Total Up Regulation									339			146	
Total Down Regulation									188			296	
Total FFR2 Capacity									47			32	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		32.7	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		96.1	60.5Hz Output		0.0

Table O-64. Unit Commitment and Dispatch 2021

Table O-64 shows the unit commitment and dispatch for the typical hour (2/23/21, 10:00 AM) and boundary hour (3/14/21, 3:00 AM).

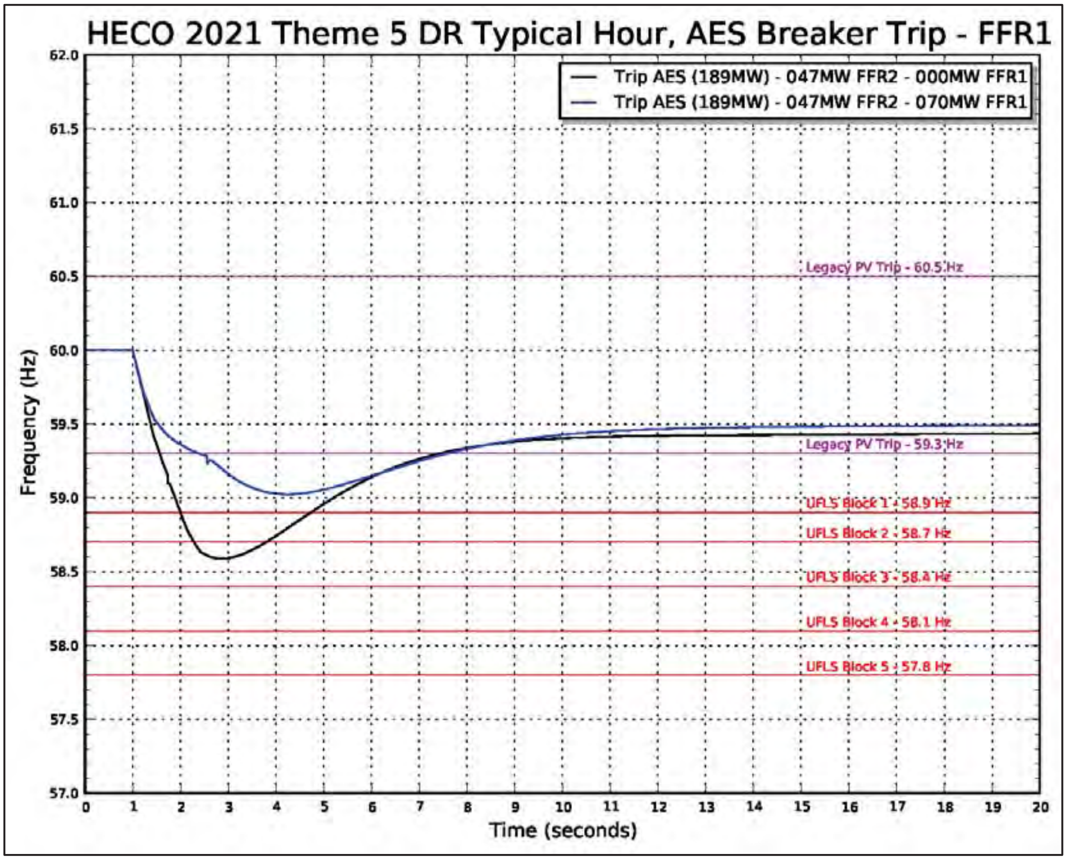

Figure O-147. Frequency Response Profile FFR1 Typical Hour

Figure O-147 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4087 MW-sec, the capacity of FFR2 is 47 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 32.7 MW. With no FFR1, the frequency nadir is 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 47 MW of FFR2.

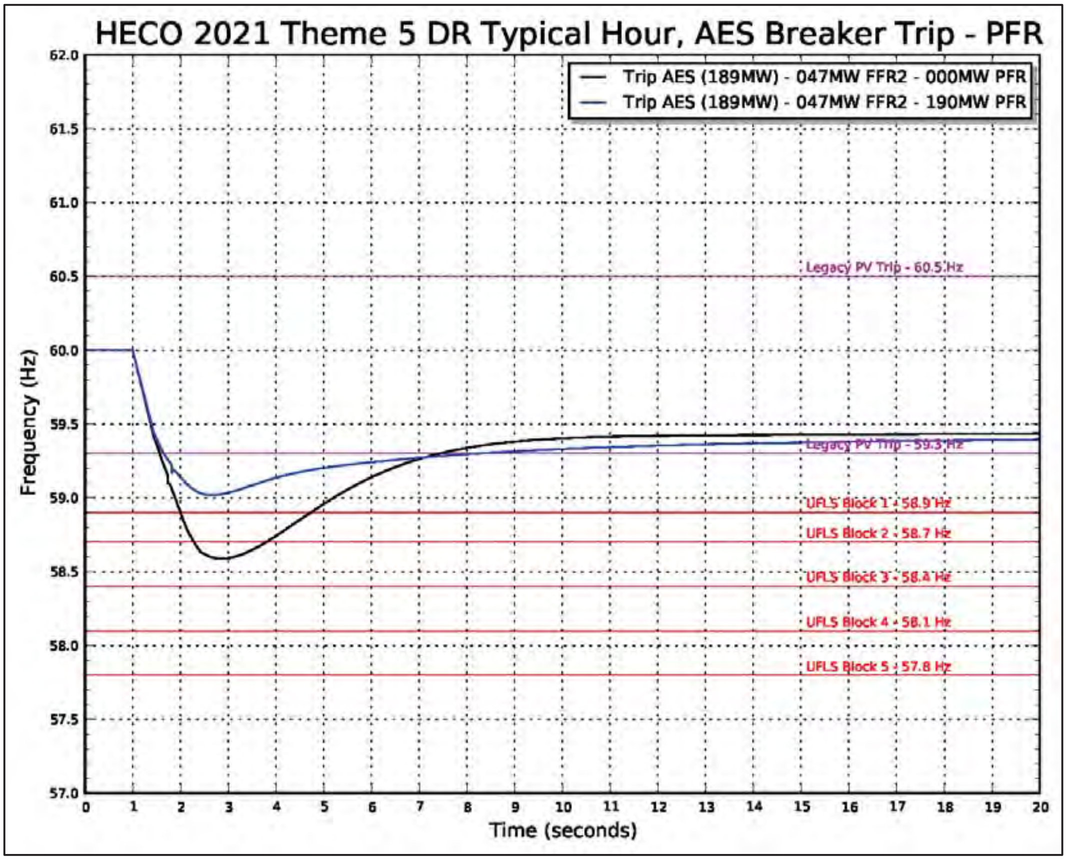

Figure O-148. Frequency Response Profile PFR Typical Hour

Figure O-148 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 190 MW. This is in addition to the 47 MW of FFR2 and 339 MW of upward regulation from thermal generation.

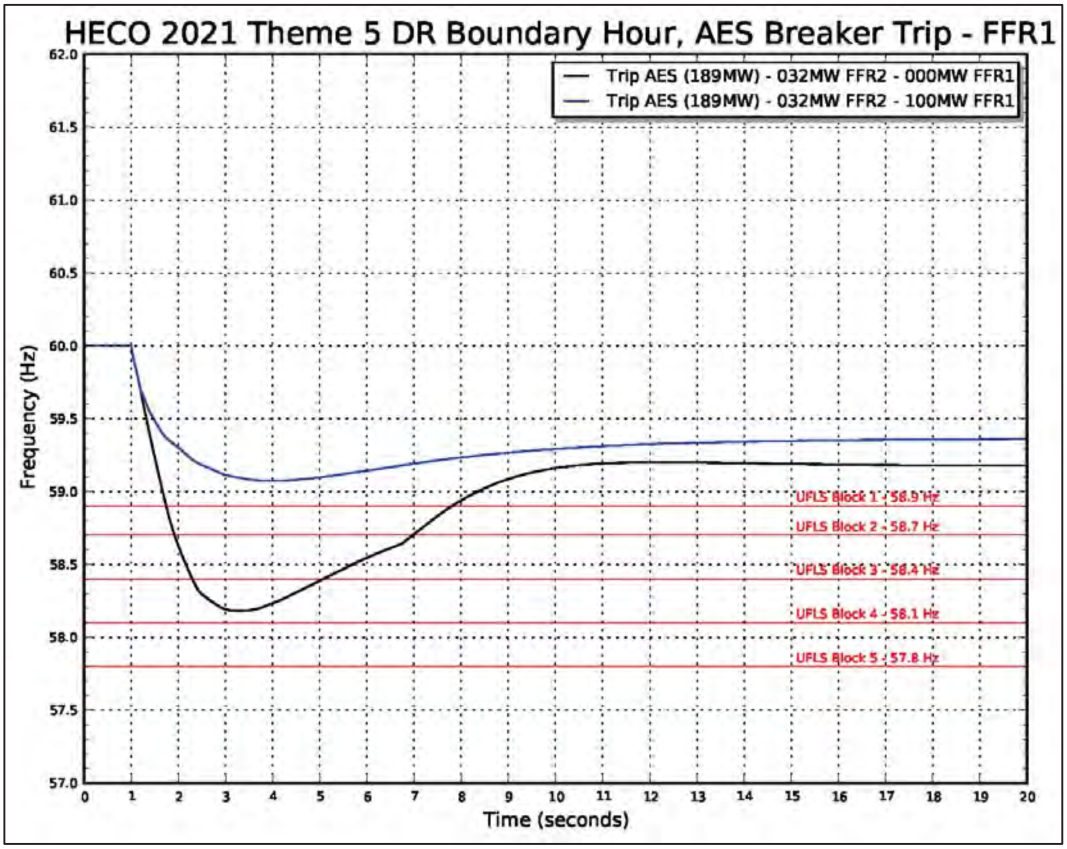

Figure O-149. Frequency Response Profile FFR1 Boundary Hour

Figure O-149 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3586 MW-sec and the capacity of FFR2 is 32 MW. With no FFR1, the frequency nadir is 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 32 MW of FFR2.

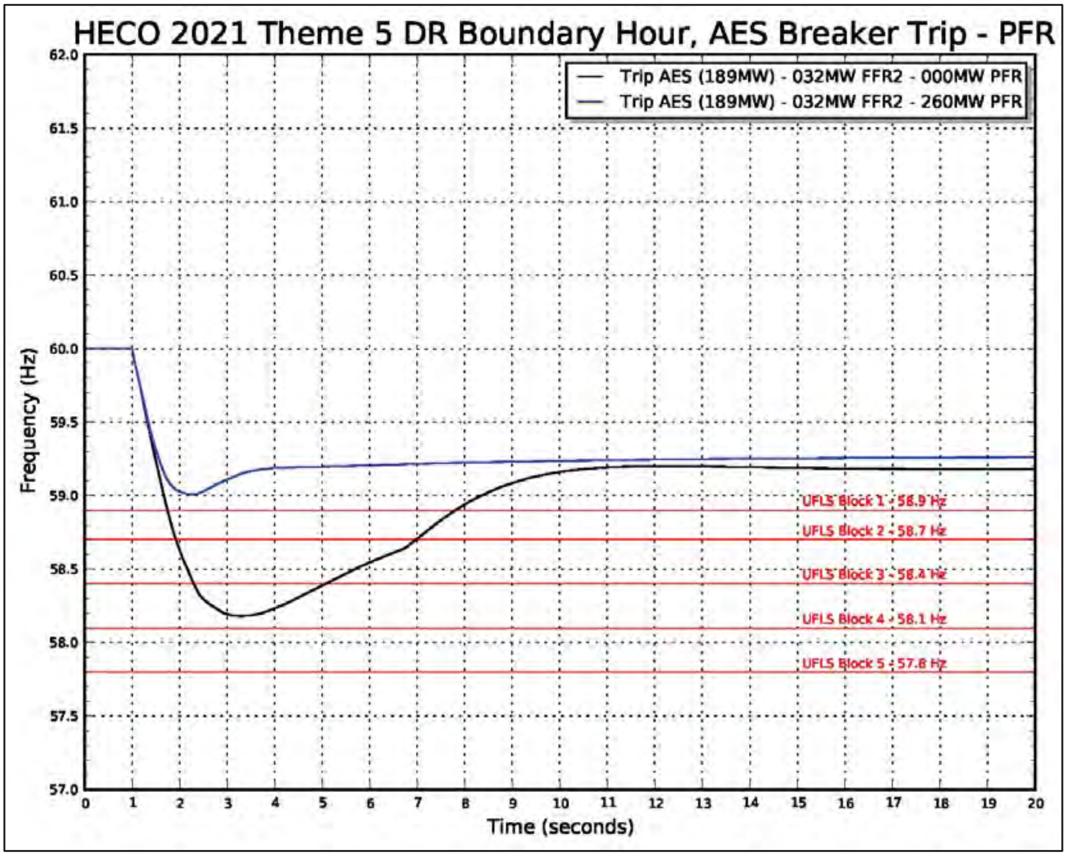

Figure O-150. Frequency Response Profile PFR Boundary Hour

Figure O-150 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 32 MW of FFR2 and 146 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Tue 2/23/21 Hour 10			DR - K5 Trip Boundary Sun 3/14/21 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	104.0	85.0	41.0	104.0	85.0	41.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	62.7	21.3	33.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	14.9	5.1	4.9	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	32.1	54.1	8.4			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357				41.3	44.0	17.7
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						30			53		
-Kahuku	30	0						1			11		
-Kawailoa	69	0						12			13		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						4			2		
DG-PV	712	0						321			0		
Station PV	463	0						272			0		
Total Kinetic Energy								3996			3591		
Total Load								1066			576		
Total Thermal Generation								444			523		
Total Renewable Generation								622			53		
Total Generation								1066			576		
Excess Generation								0			0		
Total Up Regulation								303			140		
Total Down Regulation								214			322		
Total FFR2 Capacity								47			32		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		32.7	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		96.1	60.5Hz Output		0.0

Table O-65. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-65 shows the unit commitment and dispatch for the typical hour (2/23/21, 10:00 AM) and boundary hour (3/14/21, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

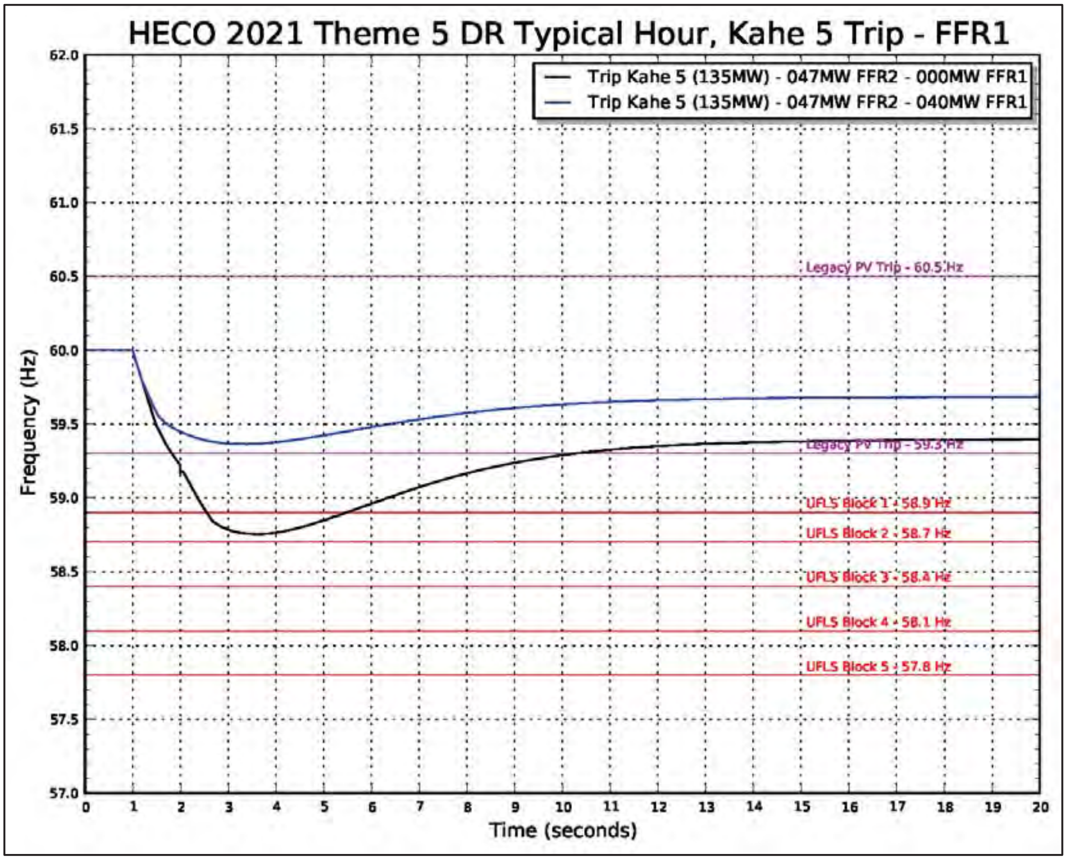

Figure O-151. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-151 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3996 MW-sec, the capacity of FFR2 is 47 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 33 MW. With no additional FFR, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 47 MW of FFR2.

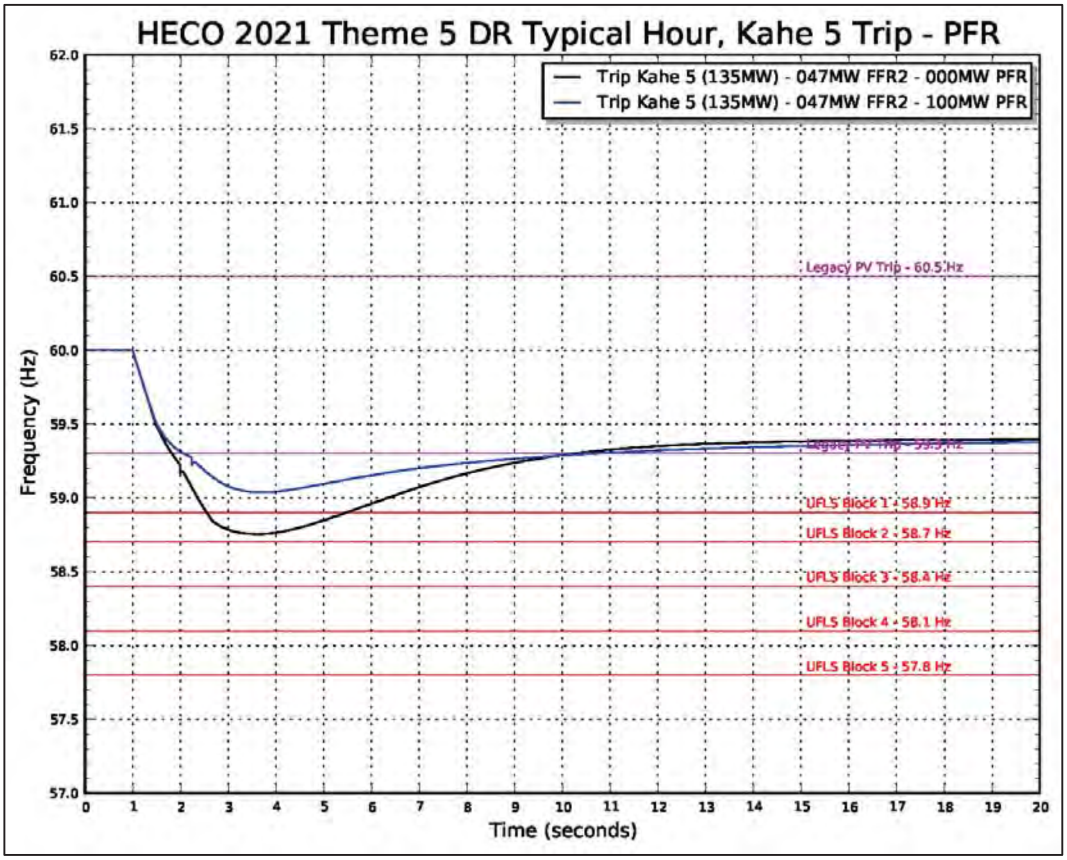

Figure O-152. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-152 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 47 MW of FFR2 and 303 MW of upward regulation from thermal generation.

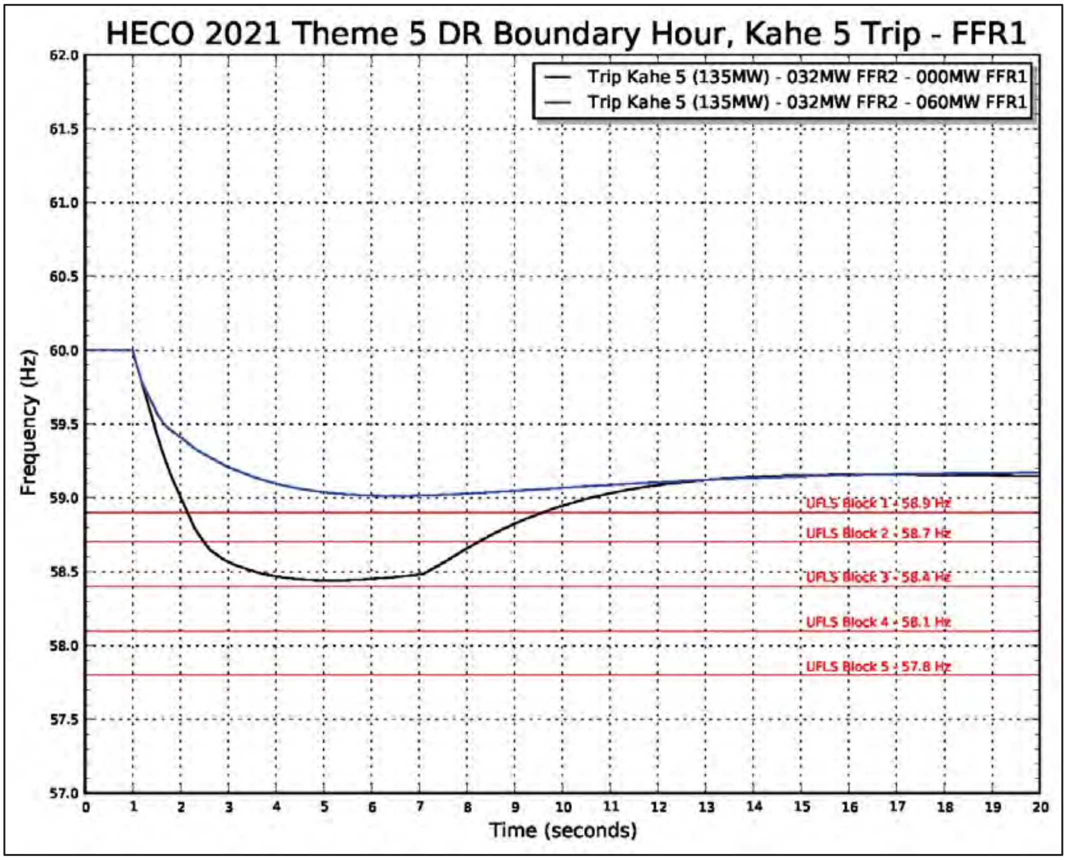

Figure O-153. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-153 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3591 MW-sec and the capacity of FFR2 is 32 MW. With no additional FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 32 MW of FFR2.

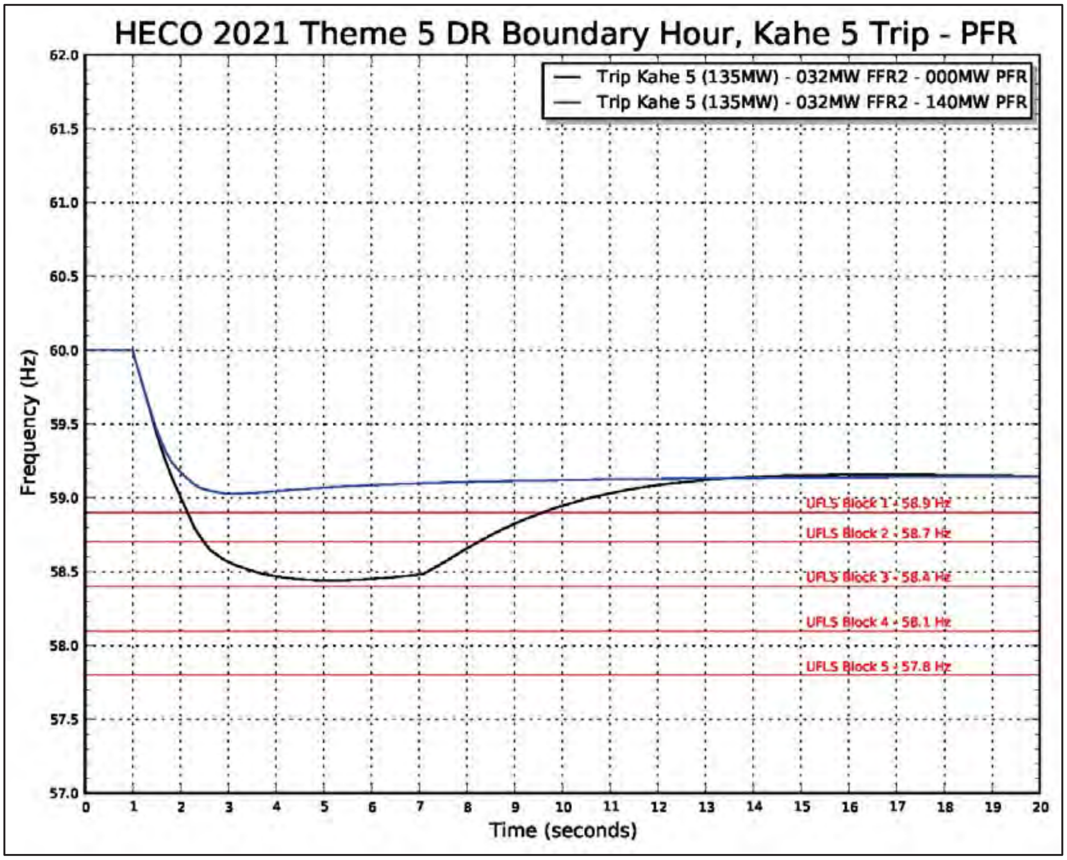

Figure O-154. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-154 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 140 MW. This is in addition to the 32 MW of FFR2 and 140 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Sun 7/11/21 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261	25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						54		
-Kahuku	30	0						11		
-Kawailoa	69	0						19		
-Na Pua Makani	24	0						21		
-CBRE Wind	10	0						3		
DG-PV	712	0						533		
Station PV	463	0						273		
Total Kinetic Energy									3069	
Total Load									1098	
Total Thermal Generation									238	
Total Renewable Generation									860	
Total Generation									1098	
Excess Generation									0	
Total Up Regulation									350	
Total Down Regulation									30	
Total FFR2 Capacity									53	
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			73.5 215.9				59.3Hz Output 60.5Hz Output		54.5 160.2

Table O-66. Unit Commitment and Dispatch Fault Analysis 2021

Table O-66 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 806 MW and the capacity of demand response is 53 MW.

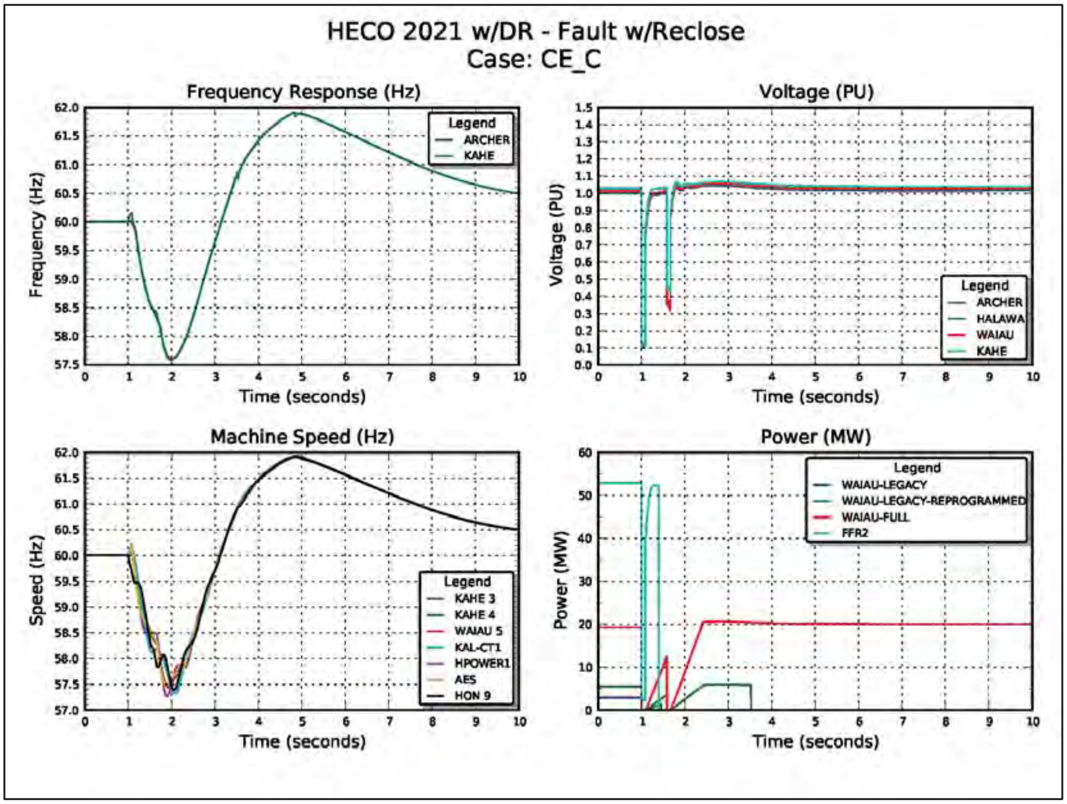

Figure O-155. System Performance for Normally Cleared Fault

Figure O-155 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU threshold where the 806 MW of inverter-based generation momentarily drops to zero, driving system frequency to 57.6 Hz. System voltage is restored within 0.5 seconds so some DG-PV generation is restored. The aggregate response from synchronous units, the restoration of DG-PV generation, five blocks of UFLS, and 53 MW of FFR2 is able to stabilize system frequency but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Waiau that is indicative of all inverter-based generation on the system.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

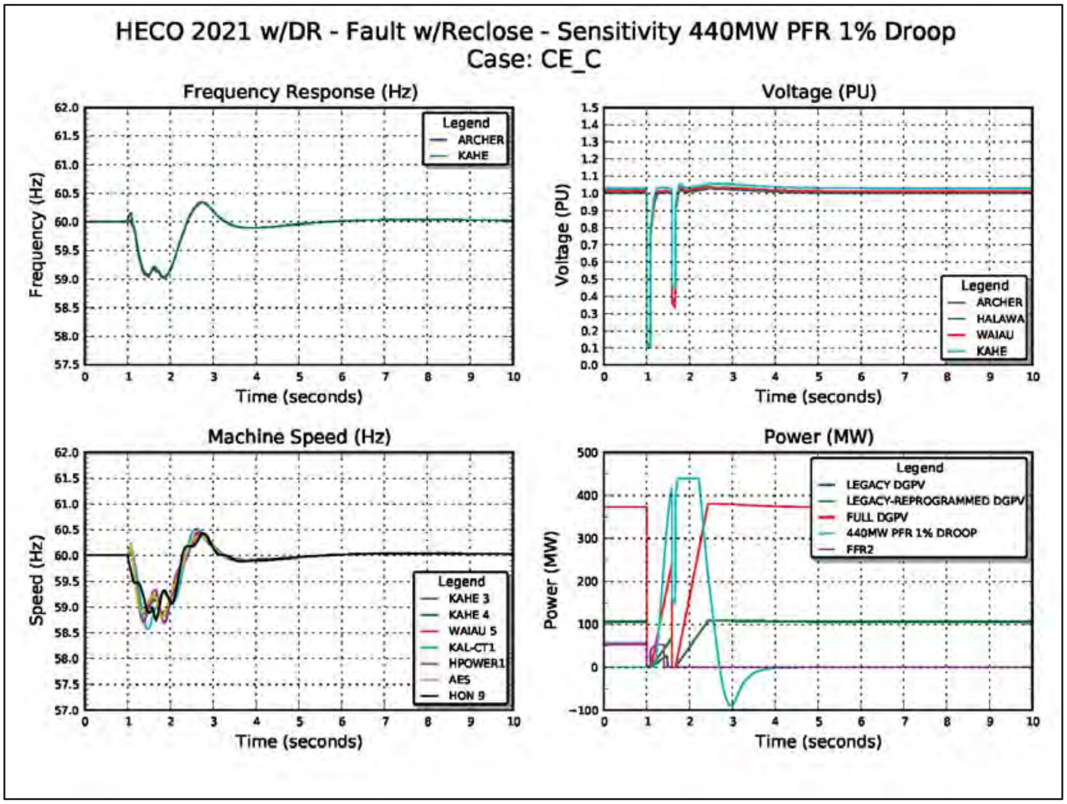

Figure O-156. System Performance Sensitivity Analysis 440 MW PFR

Figure O-156 shows system performance with the addition of 440 MW of PFR at 1% droop response. For the purpose of this analysis, a 440 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 440 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

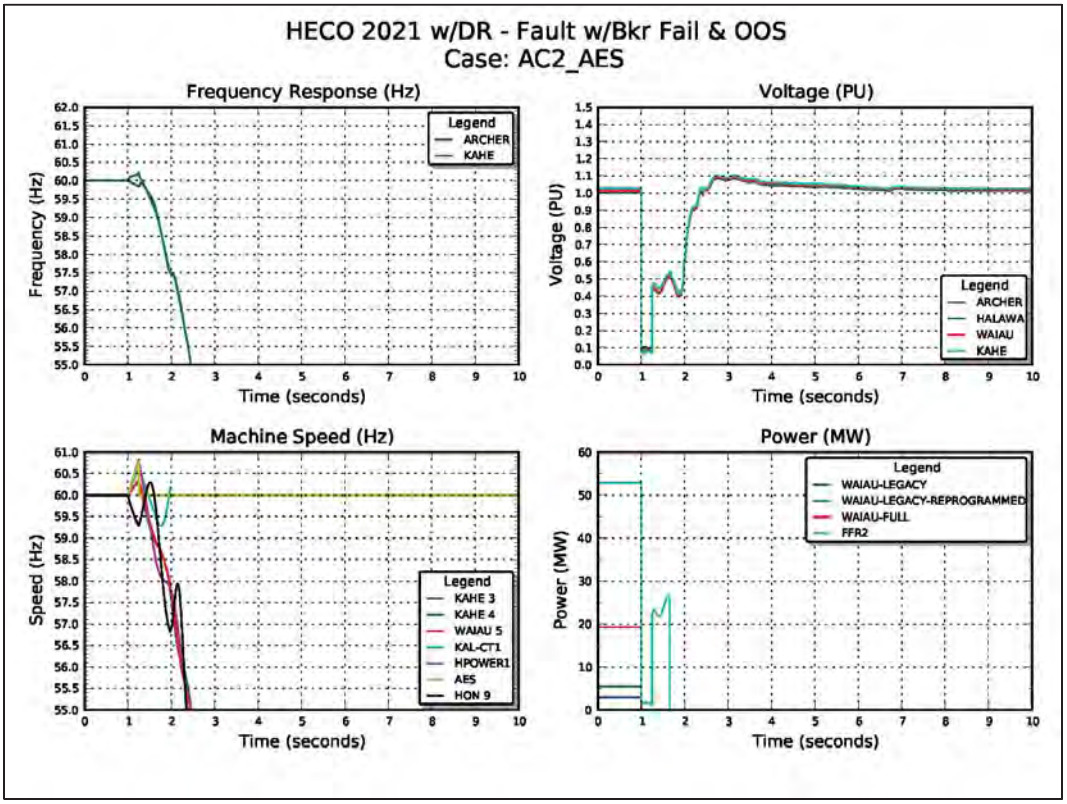

Figure O-157. System Performance for Breaker Failure Analysis

Figure O-157 shows four plots that illustrate system performance for a fault on the AES-CEIP 2 circuit and BKR 323 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the AES bus and tripping 63 MW. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 806 MW of inverter-based generation to trip offline. The net loss of generation contingency is 869 MW, driving system frequency below 56.0 Hz so the remaining synchronous generators trip offline on under frequency protection. The BKR 323 failure is the only simulation that resulted in system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

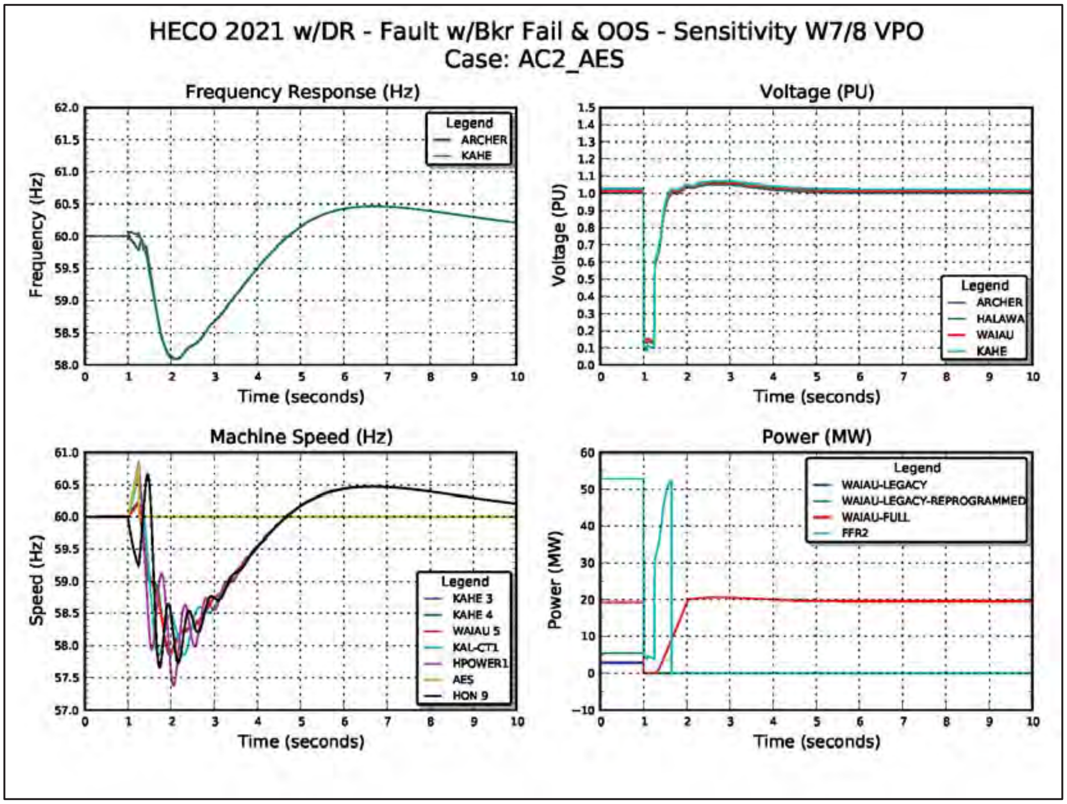

Figure O-158. System Performance Sensitivity Analysis VPO Units

Figure O-158 shows system performance with Waiau Units 7 and 8 operating in VPO. The aggregate response from synchronous generators, restoration of full ride-through DG-PV, and four blocks of UFLS are required to stabilize system frequency. With additional synchronous units at Waiau, system voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting so generation from full ride-through inverters is restored, arresting frequency decay at 58.0 Hz. The system is stable but is not in compliance with TPL-001.

2021 138 kV Fault Analysis

Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition	Waiau 7/8 VPO Mitigation
AES-CEIP 1	AES	320	15	AES-HP	Stable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Stable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Stable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Stable	Stable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Stable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Stable	Stable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Stable	Stable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-67. Summary of Results Breaker Failure Analysis

Table O-67 shows the results for the breaker failure analysis. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency but multiple blocks of UFLS was also required.

The system requires 440 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2022

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

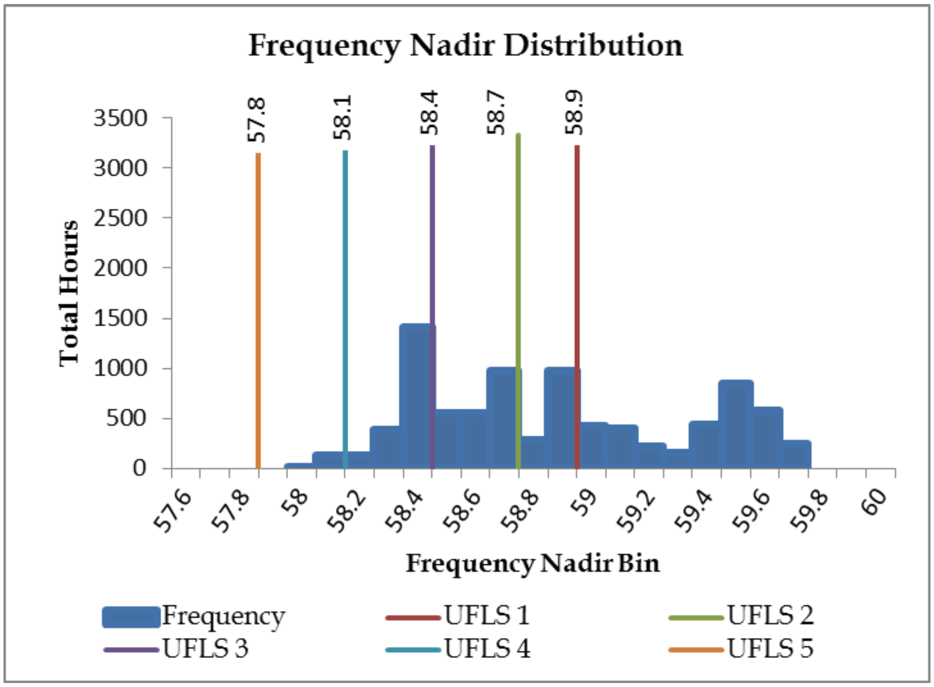

Figure O-159. Frequency Nadir Histogram 2022

Figure O-159 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1412 hours was 8:00 AM on Friday, August 5. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the distribution of one hour was 3:00 AM on Monday, March 21. The frequency nadir range for the boundary hour is 57.9 – 58.0 Hz that requires four blocks of UFLS to stabilize system frequency.

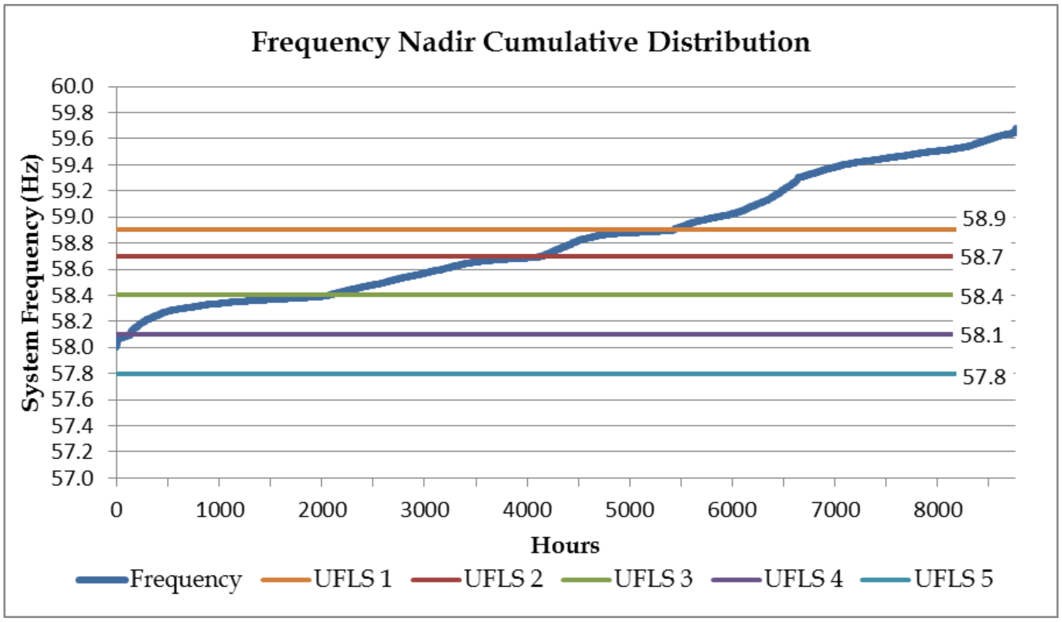

Figure O-160. Frequency Nadir Duration Curve 2022

Figure O-160 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for5424 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Fri 8/5/22 Hour 8			DR - AES Trip Boundary Mon 3/21/22 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	45.4	40.8	21.7			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	41.7	43.6	18.1			
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426				43.3	40.0	19.5
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	30.2	56.0	6.1	44.0	42.2	19.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1	14.6	2.2	7.9
JBPHH 2	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						40			59		
-Kahuku	30	0						13			13		
-Kawailoa	69	0						19			17		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	729	0						91			0		
Station PV	543	0						56			0		
Total Kinetic Energy								3869			3416		
Total Load								804			593		
Total Thermal Generation								616			534		
Total Renewable Generation								187			59		
Total Generation								804			593		
Excess Generation								0			0		
Total Up Regulation								140			95		
Total Down Regulation								366			323		
Total FFR2 Capacity								38			33		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		9.5	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		27.8	60.5Hz Output		0.0

Table O-68. Unit Commitment and Dispatch 2022

Table O-68 shows the unit commitment and dispatch for the typical hour (8/5/22, 8:00 AM) and boundary hour (3/21/22, 3:00 AM).

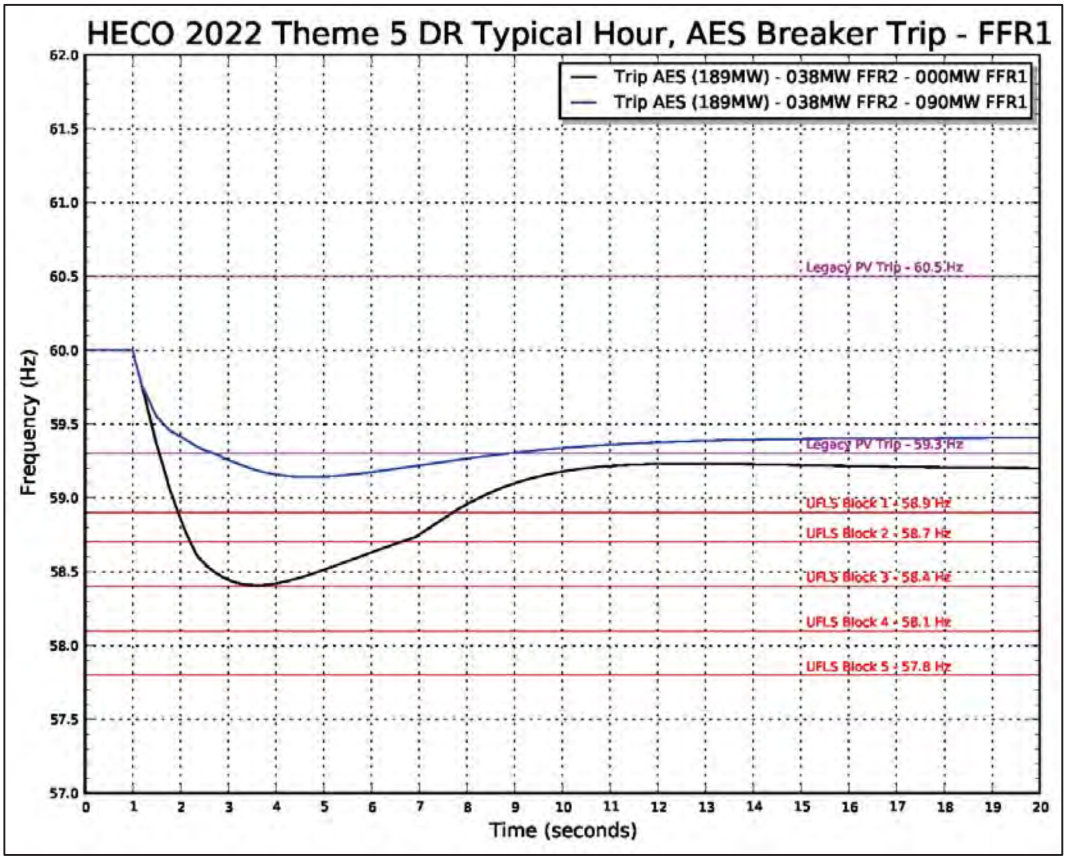

Figure O-161. Frequency Response Profile FFR1 Typical Hour

Figure O-161 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3869 MW-sec, the capacity of FFR2 is 38 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 9.5 MW. With no FFR1, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 38 MW of FFR2.

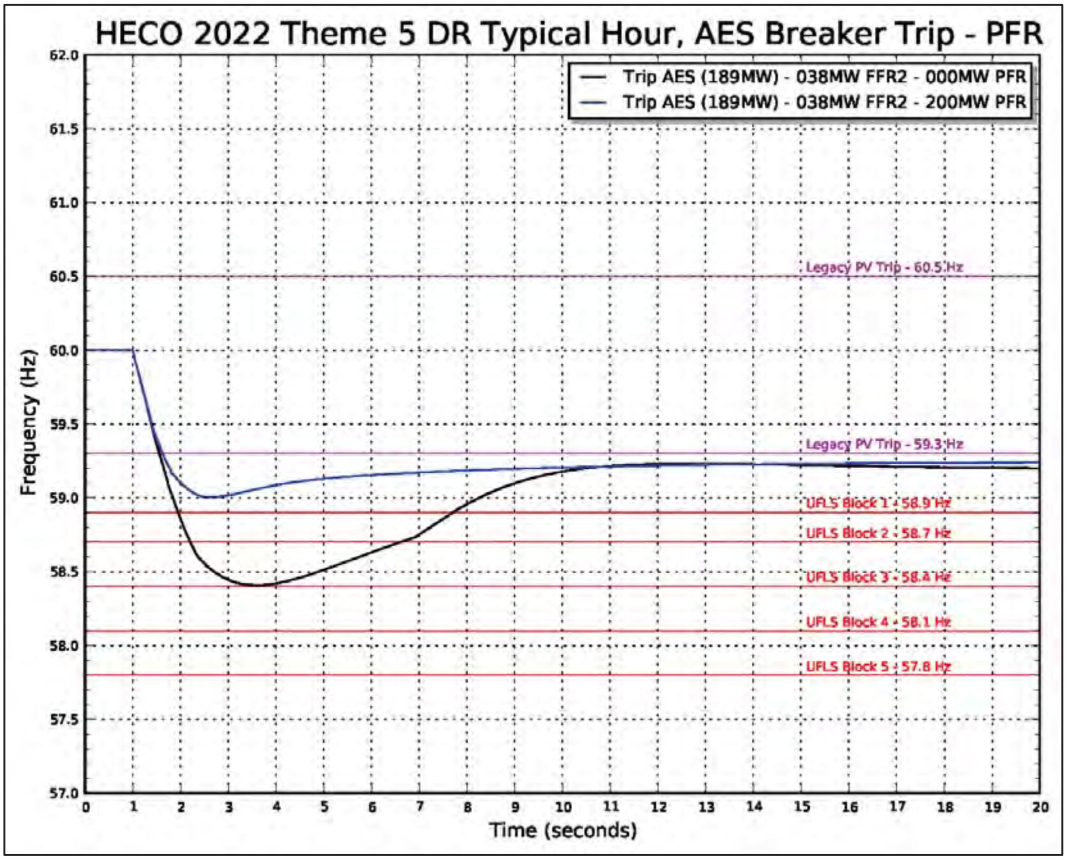

Figure O-162. Frequency Response Profile PFR Typical Hour

Figure O-162 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 38 MW of FFR2 and 140 MW of upward regulation from thermal generation.

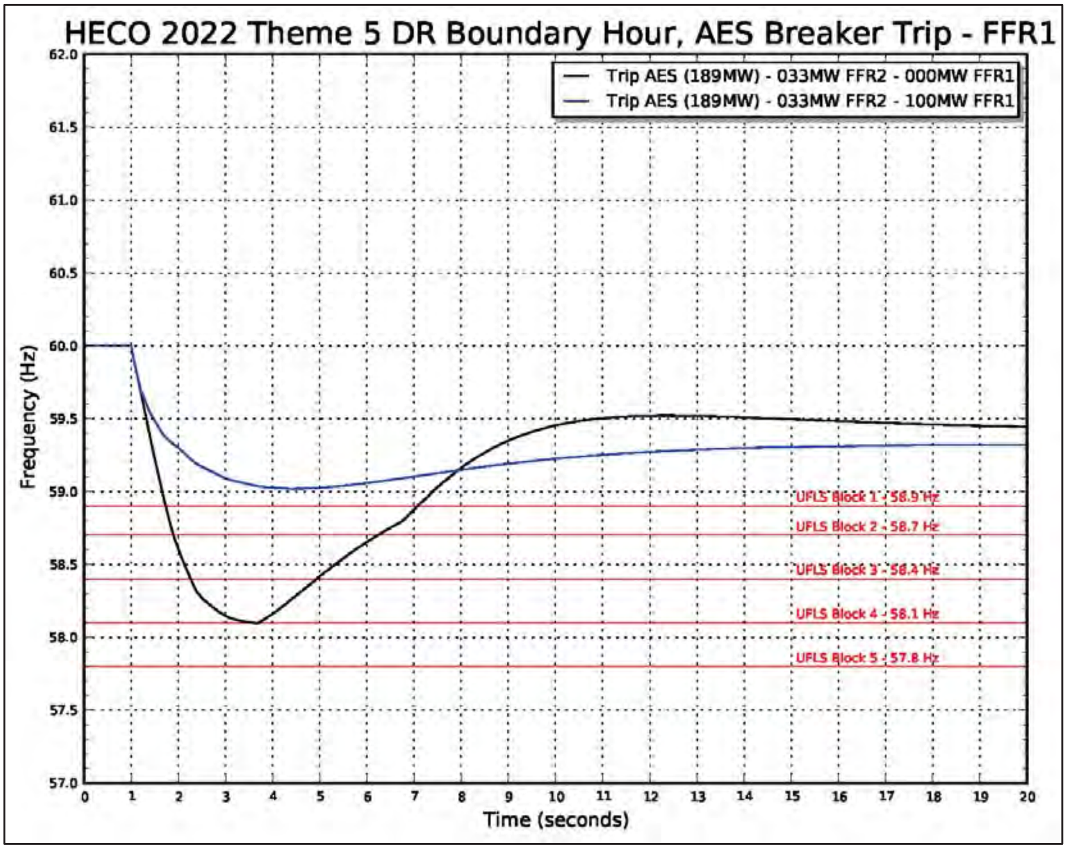

Figure O-163. Frequency Response Profile FFR1 Boundary Hour

Figure O-163 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3416 MW-sec and the capacity of FFR2 is 33 MW. With no additional FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 33 MW of FFR2.

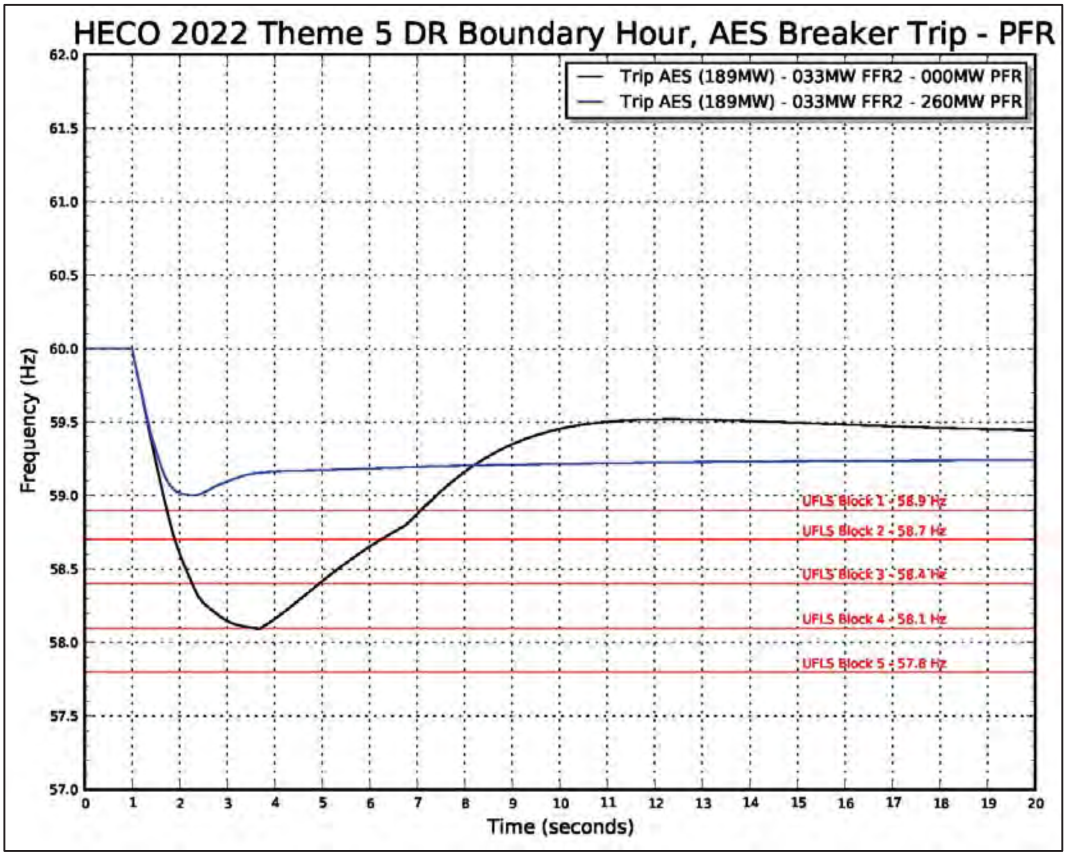

Figure O-164. Frequency Response Profile PFR Boundary Hour

Figure O-164 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 33 MW of FFR2 and 95 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 8/5/22 Hour 8			DR - K5 Trip Boundary Mon 3/21/22 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615	134.0	55.0	71.0	112.0	77.0	49.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	38.2	48.0	14.1	44.0	42.2	19.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 2	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						40			59		
-Kahuku	30	0						13			13		
-Kawailoa	69	0						19			17		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	729	0						91			0		
Station PV	543	0						56			0		
Total Kinetic Energy									3847			3660	
Total Load									804			593	
Total Thermal Generation									617			534	
Total Renewable Generation									187			59	
Total Generation									804			592	
Excess Generation									0			0	
Total Up Regulation									103			130	
Total Down Regulation									392			332	
Total FFR2 Capacity									38			33	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		9.5	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		27.8	60.5Hz Output		0.0

Table O-69. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-69 shows the unit commitment and dispatch for the typical hour (8/5/22, 8:00 AM) and boundary hour (3/21/22, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

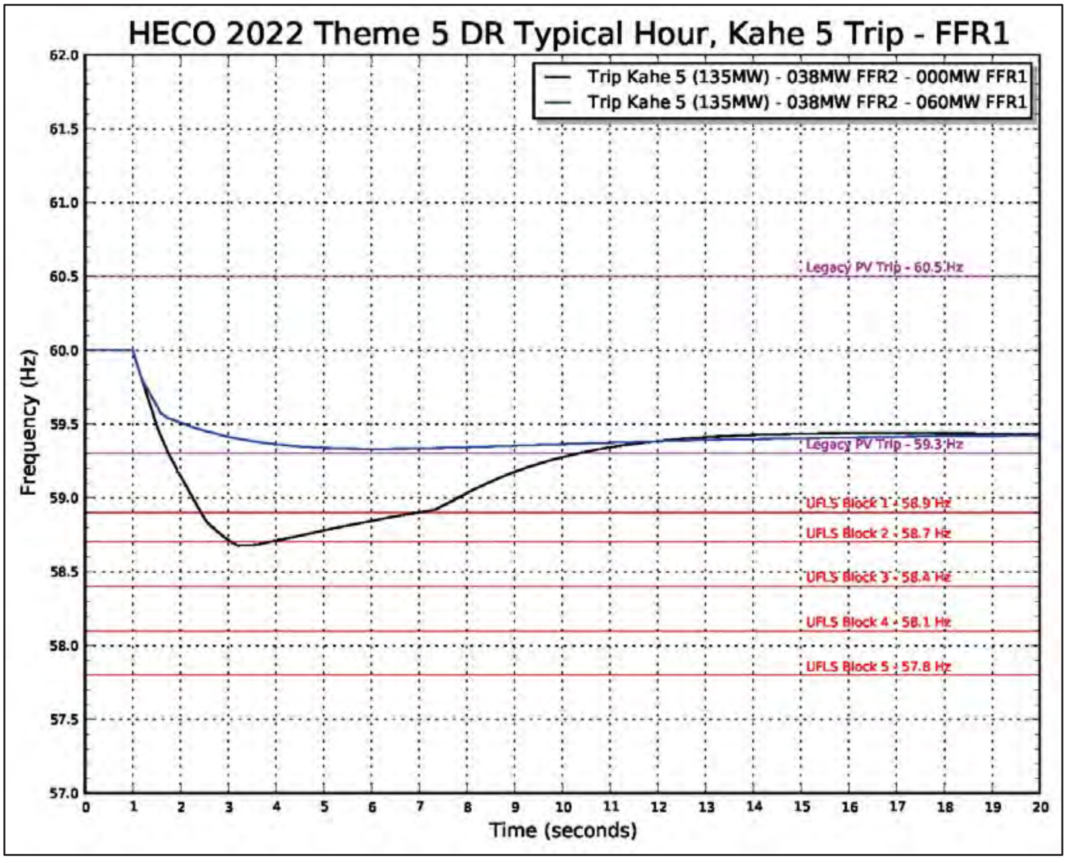

Figure O-165. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-165 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3847 MW-sec, the capacity of FFR2 is 38 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 9.5 MW. With no FFR1, the frequency nadir breaches 58.7 Hz. Two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 38 MW of FFR2.

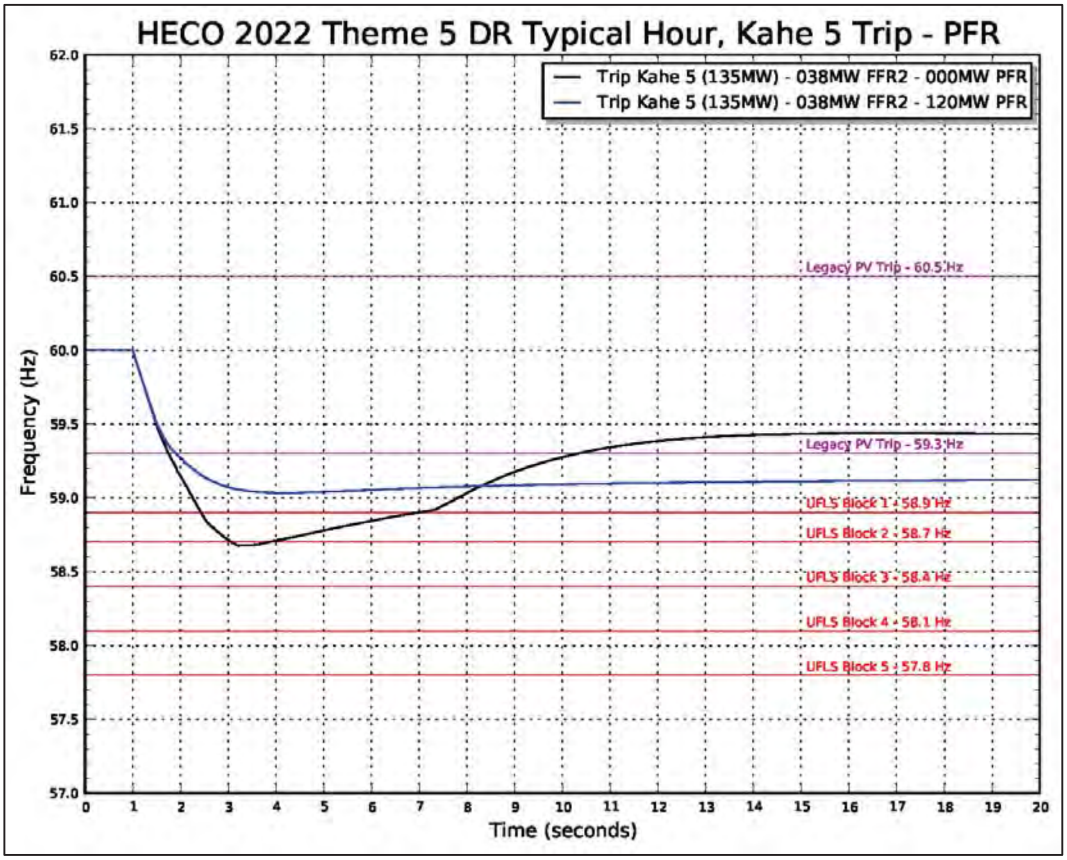

Figure O-166. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-166 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 120 MW. This is in addition to the 38 MW of FFR2 and 103 MW of upward regulation from thermal generation.

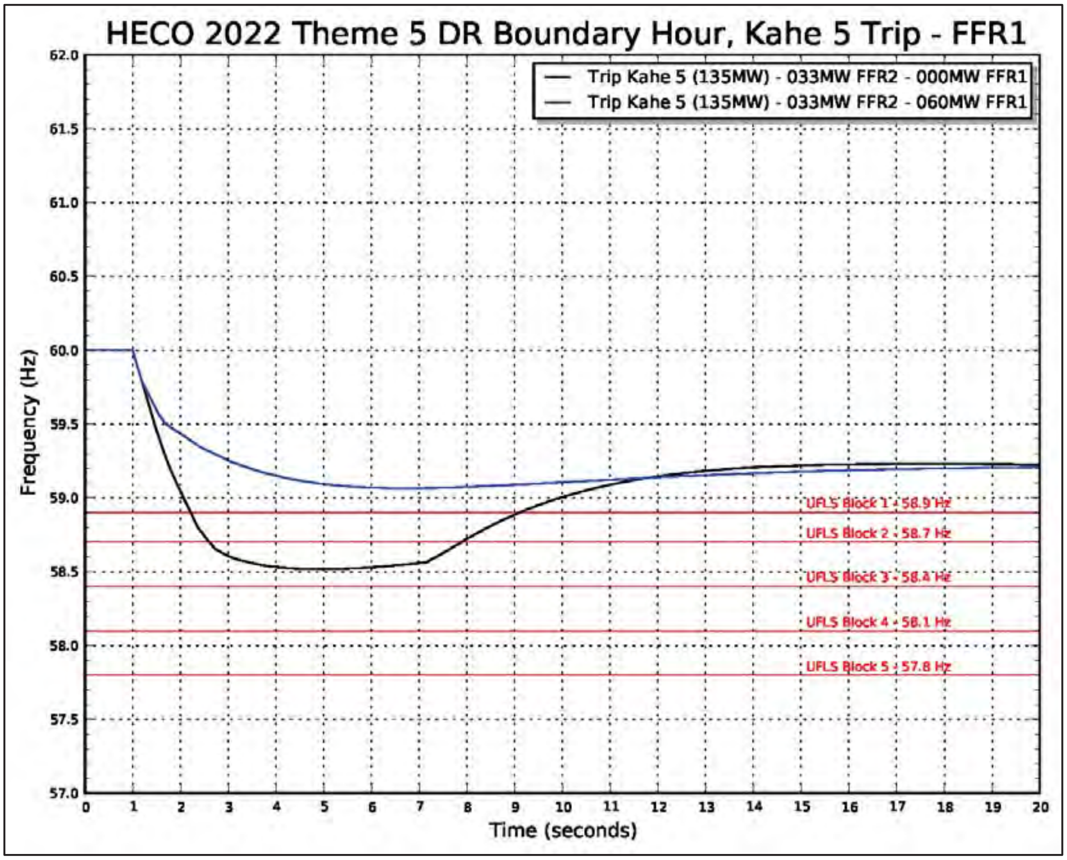

Figure O-167. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-167 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3660 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 33 MW of FFR2.

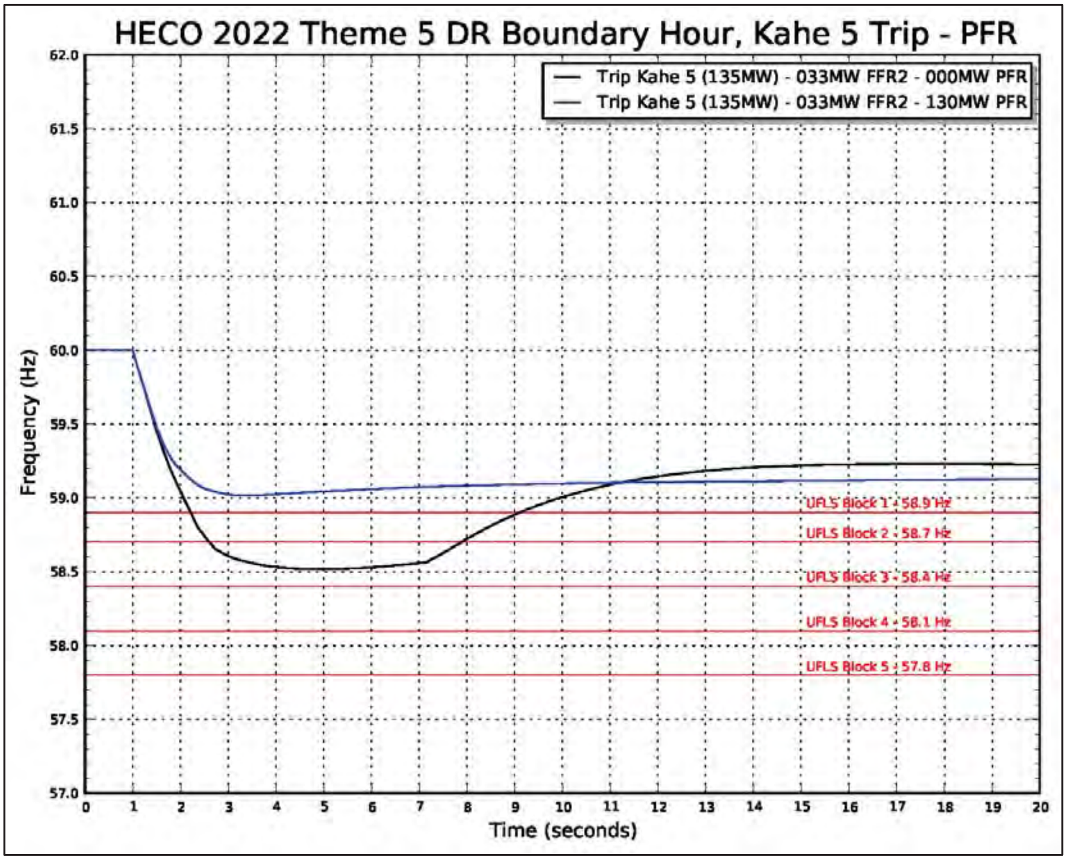

Figure O-168. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-168 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 33 MW of FFR2 and 130 MW of upward regulation from thermal generation.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

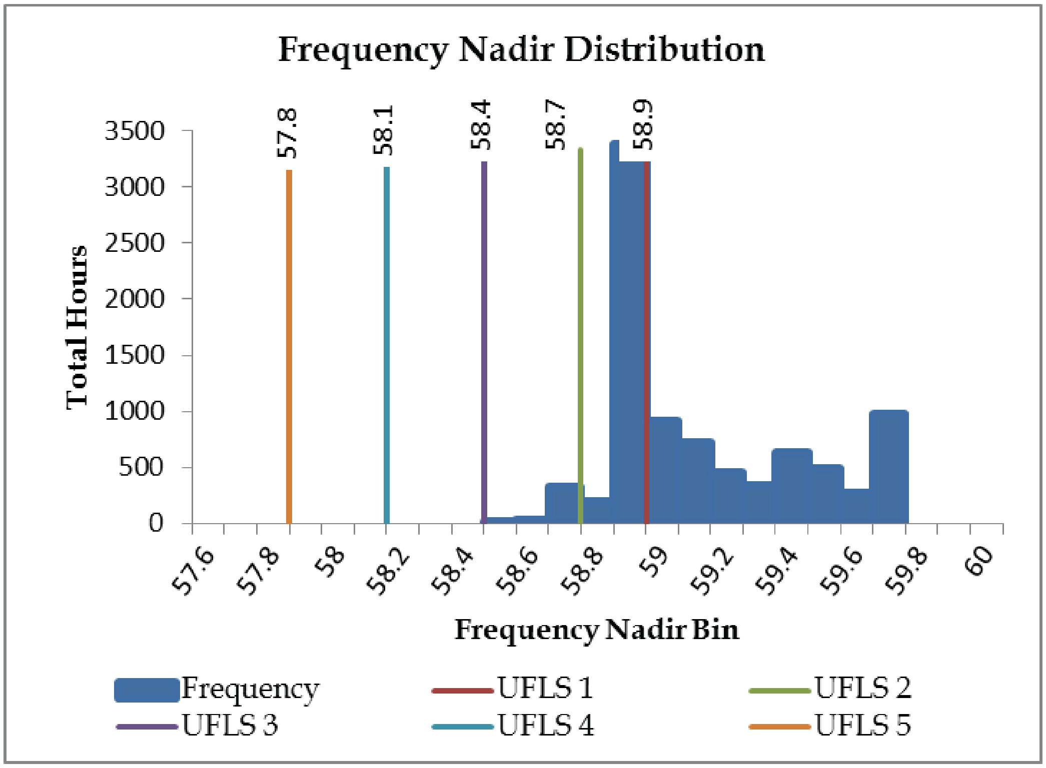

Figure O-169. Frequency Nadir Histogram 2023

Figure O-169 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 3387 hours was 8:00 PM on Friday, February 17. The frequency nadir range for the typical hour is 58.8- 58.9 Hz that requires one block of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 5 hours was 12:00 AM on Saturday, January 28. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires four blocks of UFLS to stabilize system frequency.

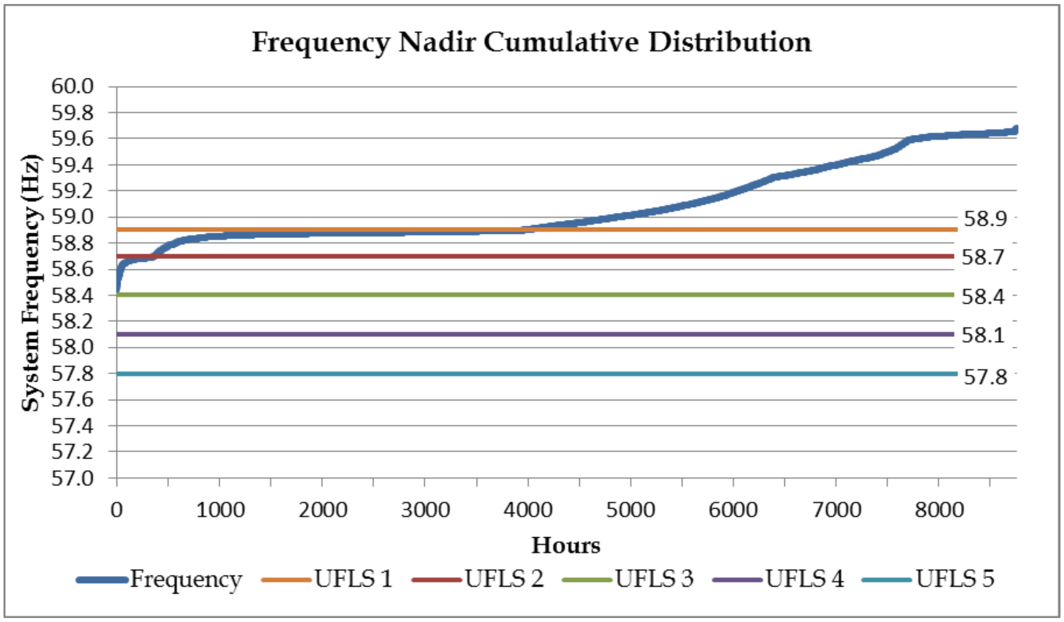

Figure O-170. Frequency Nadir Duration Curve 2023

Figure O-170 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 3957 hours of the year.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 2/17/23 Hour 20			DR - K5 Trip Boundary Sat 1/28/23 Hour 24		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	82.2	0.0	58.4			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	82.2	0.0	58.4			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	86.2	0.0	62.5			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	85.3	0.0	61.7	85.3	0.0	61.7
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256	25.0	28.7	1.2			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426				59.0	27.2	34.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11	4.0	4.0	2.0			
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 2	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 3	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 4	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 5	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 6	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3			
KMCBH 1	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 2	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 3	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 4	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 5	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						31			38		
-Kahuku	30	0						1			2		
-Kawailoa	69	0						10			9		
-Na Pua Makani	24	0						12			12		
-CBRE Wind	10	0						2			4		
DG-PV	744	0						0			0		
Station PV	603	0						0			0		
Total Kinetic Energy									4780			3564	
Total Load									919			689	
Total Thermal Generation									889			650	
Total Renewable Generation									31			38	
Total Generation									919			689	
Excess Generation									0			0	
Total Up Regulation									67			39	
Total Down Regulation									581			433	
Total FFR2 Capacity									49			35	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-70. Unit Commitment and Dispatch 2023

Table O-70 shows the unit commitment and dispatch for the typical hour (2/17/23, 8:00 PM) and boundary hour (1/28/23, 12:00 AM).

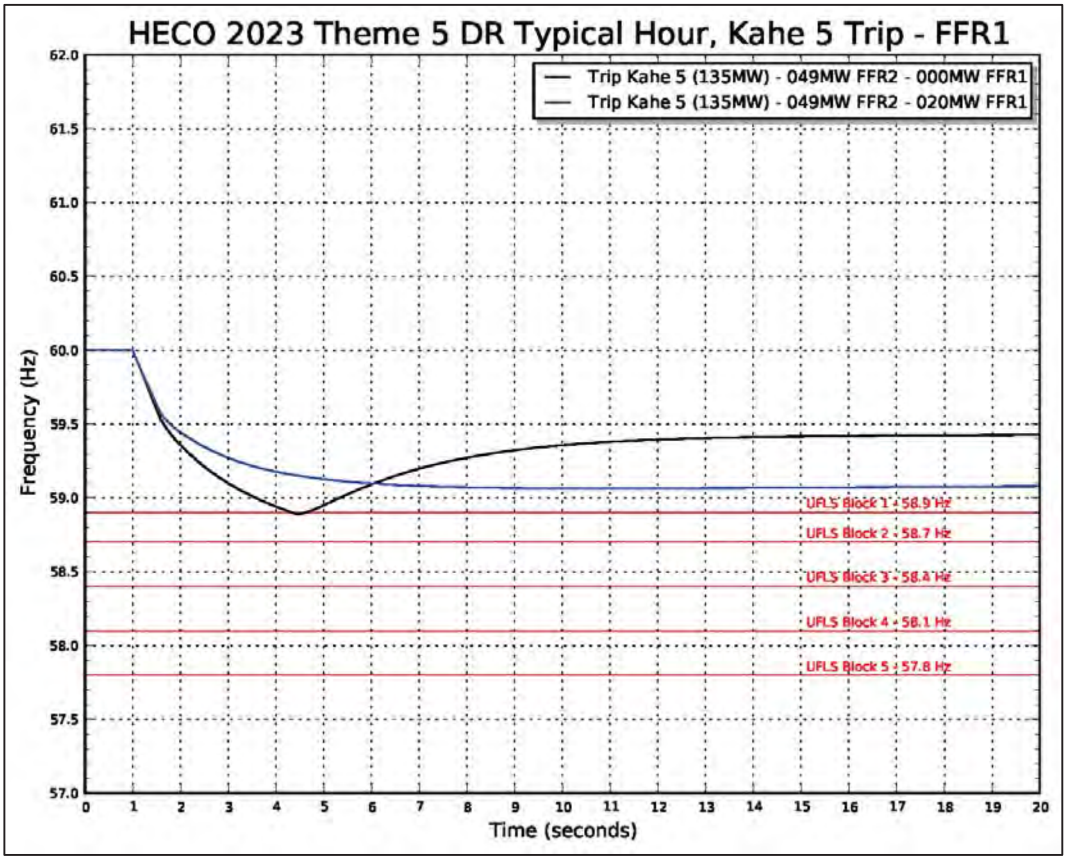

Figure O-171. Frequency Response Profile FFR1 Typical Hour

Figure O-171 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4780 MW-sec and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.9 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 20 MW. This is in addition to the 49 MW of FFR2.

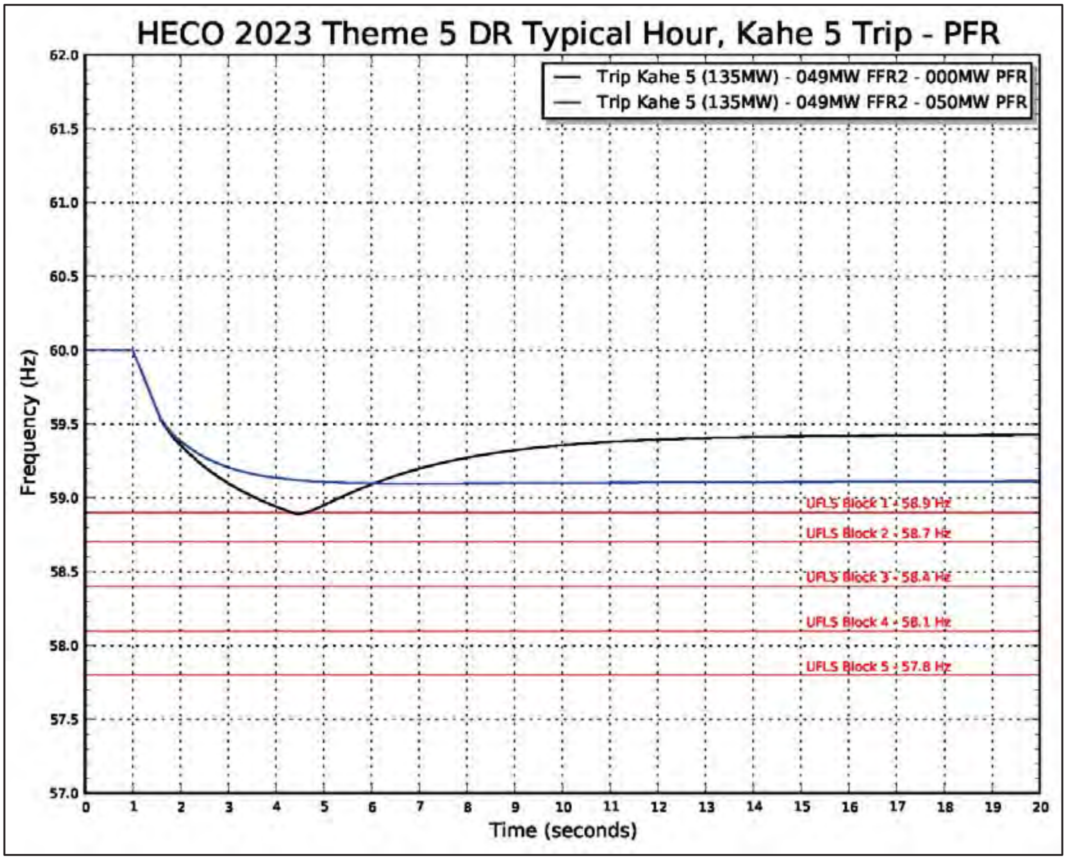

Figure O-172. Frequency Response Profile PFR Typical Hour

Figure O-172 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 50 MW. This is in addition to the 49 MW of FFR2 and 67 MW of upward regulation from thermal generation.

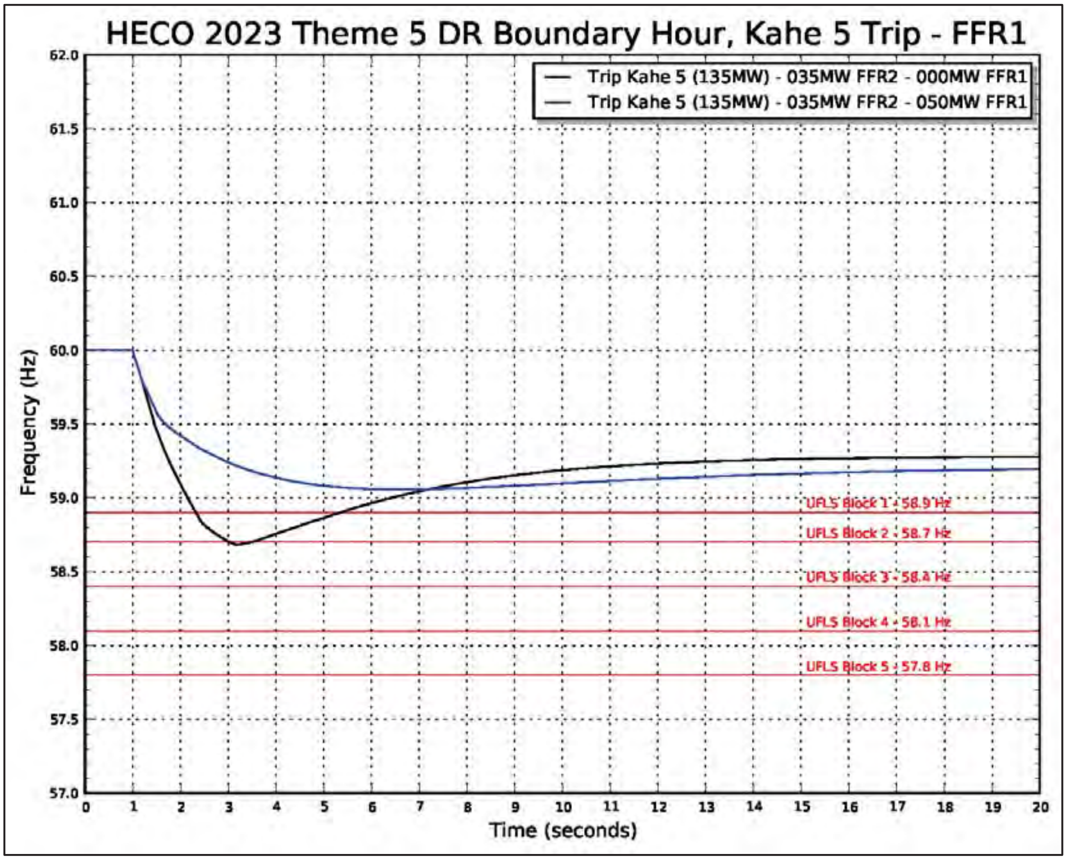

Figure O-173. Frequency Response Profile FFR1 Boundary Hour

Figure O-173 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3564 MW-sec and the capacity of FFR2 is 35 MW. With no FFR1, the frequency nadir is 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 50 MW. This is in addition to the 35 MW of FFR2.

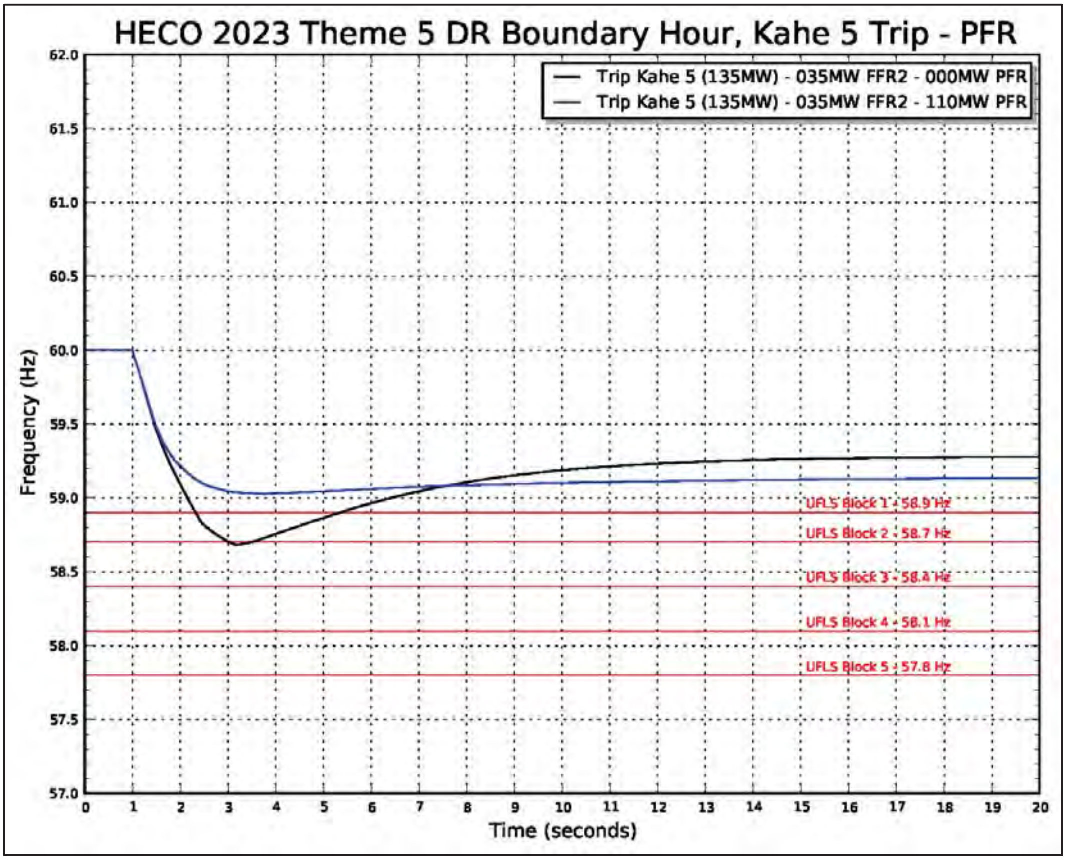

Figure O-174. Frequency Response Profile PFR Boundary Hour

Figure O-174 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 110 MW. This is in addition to the 35 MW of FFR2 and 39 MW of upward regulation from thermal generation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

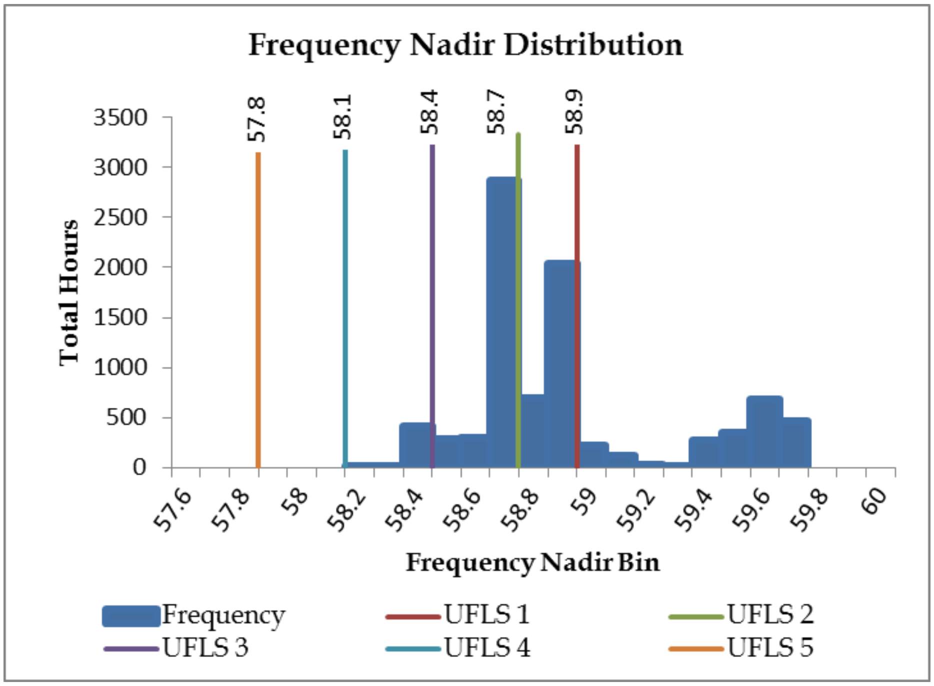

Figure O-175. Frequency Nadir Histogram 2025

Figure O-175 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2865 hours was 8:00 AM on Wednesday, June 18. The frequency nadir range for the typical hour is 58.6- 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of one hour was 3:00 AM on Monday, March 17. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires three blocks of UFLS to stabilize system frequency.

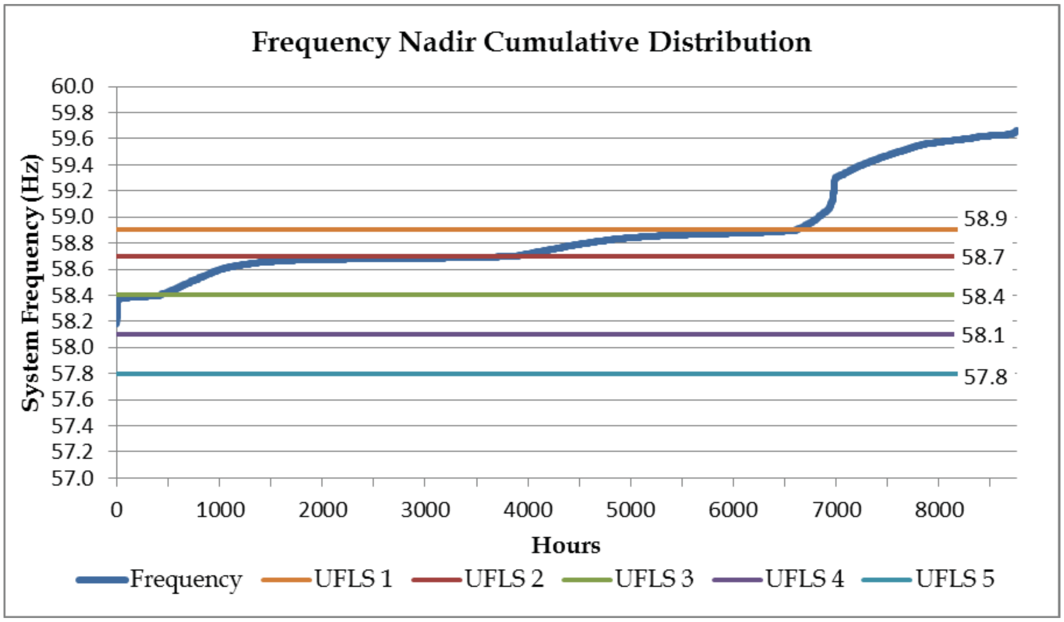

Figure O-176. Frequency Nadir Duration Curve 2023

Figure O-176 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 3957 hours of the year.

Unit	Unit Ratings							DR - GE CT1 Trip Typical Wed 6/18/25 Hour 8			DR - GE CT1 Trip Boundary Mon 3/17/25 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5	35.8	50.4	12.1
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	32.3	53.9	8.2			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 2	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 3	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 4	16.8	6.7			0.99	21.8	22				14.5	2.2	7.9
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 2	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 3	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 4	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	0.0			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278						
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						50			70		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						19			20		
-Na Pua Makani	24	0						17			18		
-CBRE Wind	10	0						2			2		
DG-PV	777	0						108			0		
Station PV	683	0						132			0		
Total Kinetic Energy								4058			3467		
Total Load								864			558		
Total Thermal Generation								573			488		
Total Renewable Generation								290			70		
Total Generation								864			558		
Excess Generation								0			0		
Total Up Regulation								114			70		
Total Down Regulation								313			274		
Total FFR2 Capacity								41			32		
Legacy DG-PV	59.3Hz Capacity	73.5						59.3Hz Output		10.1	59.3Hz Output		0.0
	60.5Hz Capacity	215.9						60.5Hz Output		29.8	60.5Hz Output		0.0

Table O-71. Unit Commitment and Dispatch 2025

Table O-71 shows the unit commitment and dispatch for the typical hour (6/18/25, 8:00 AM) and boundary hour (3/17/25, 3:00 AM).

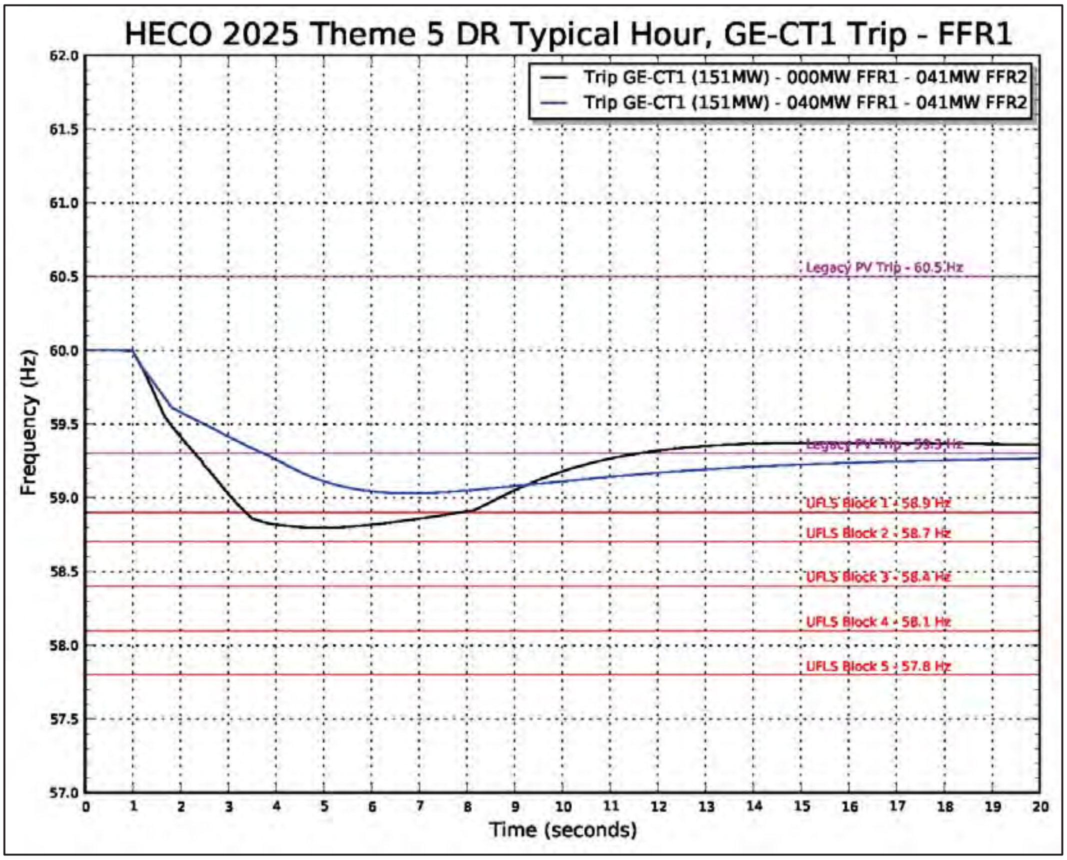

Figure O-177. Frequency Response Profile FFR1 Typical Hour

Figure O-177 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 4058 MW-sec, the capacity of FFR2 is 41 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 10.1 MW. With no FFR1, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 41 MW of FFR2.

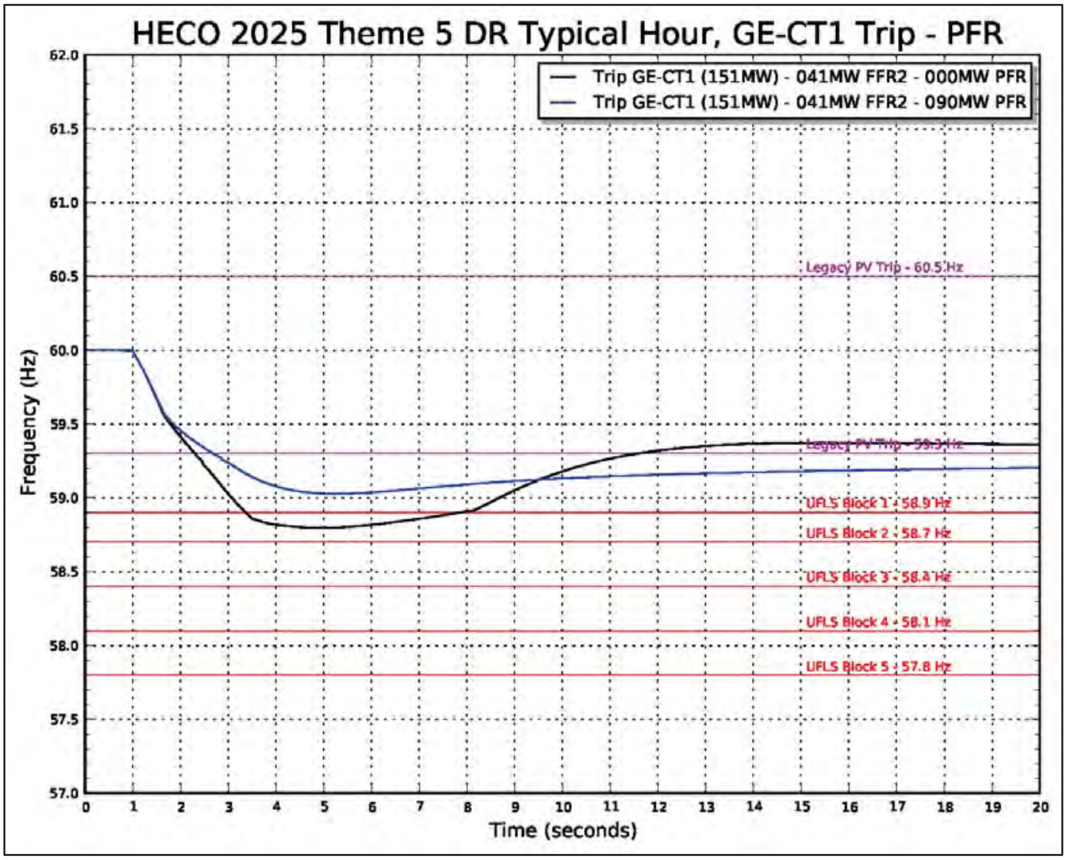

Figure O-178. Frequency Response Profile PFR Typical Hour

Figure O-178 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 41 MW of FFR2 and 114 MW of upward regulation from thermal generation.

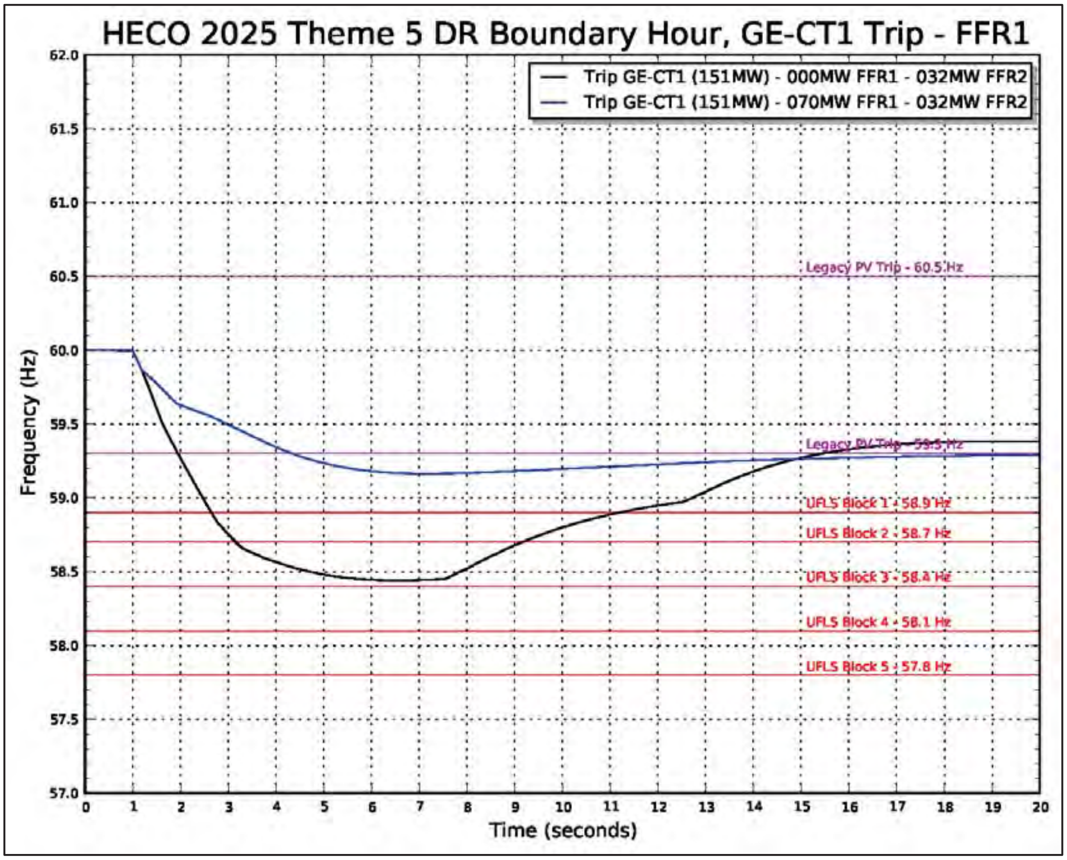

Figure O-179. Frequency Response Profile FFR1 Boundary Hour

Figure O-179 shows the frequency response profile for a GE CT1 trip in combined–cycle operation for a boundary hour. System kinetic energy is 3467 MW-sec and the capacity of FFR2 is 32 MW. With no FFR1, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 32 MW of FFR2.

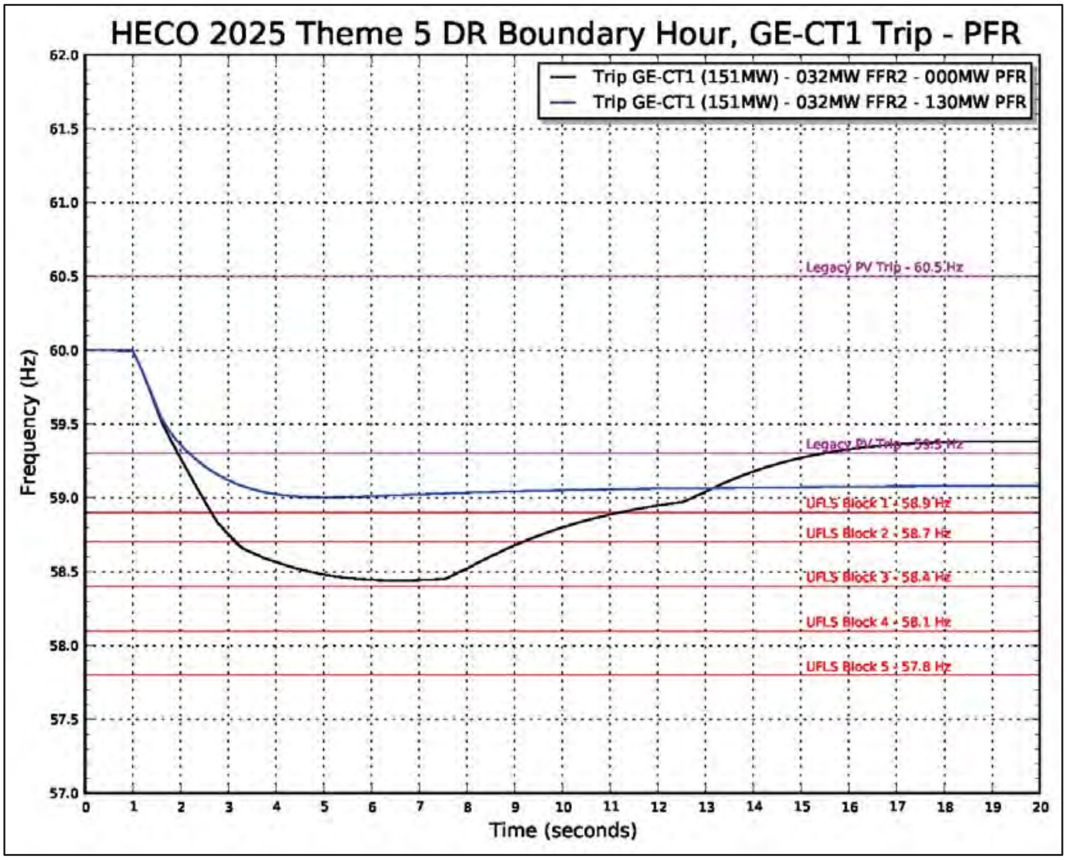

Figure O-180. Frequency Response Profile PFR Boundary Hour

Figure O-180 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 32 MW of FFR2 and 70 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

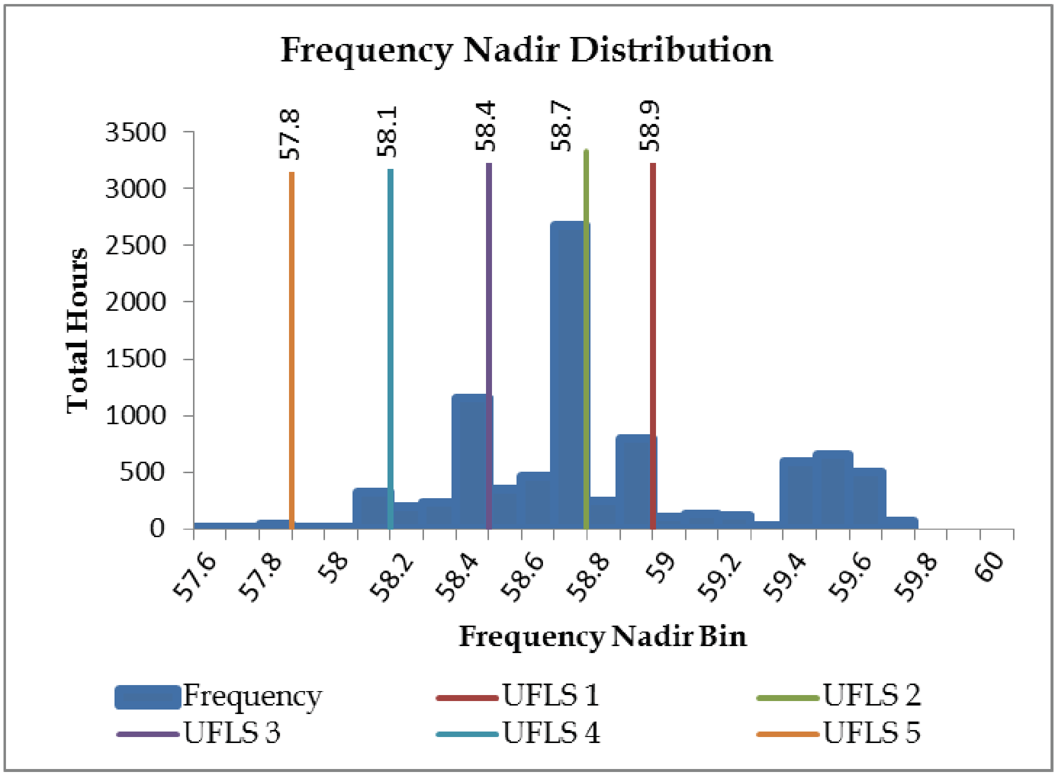

Figure O-181. Frequency Nadir Histogram 2030

Figure O-181 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1155 hours was 1:00 AM on Monday, September 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 39 hours was 3:00 AM on Wednesday, April 17. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

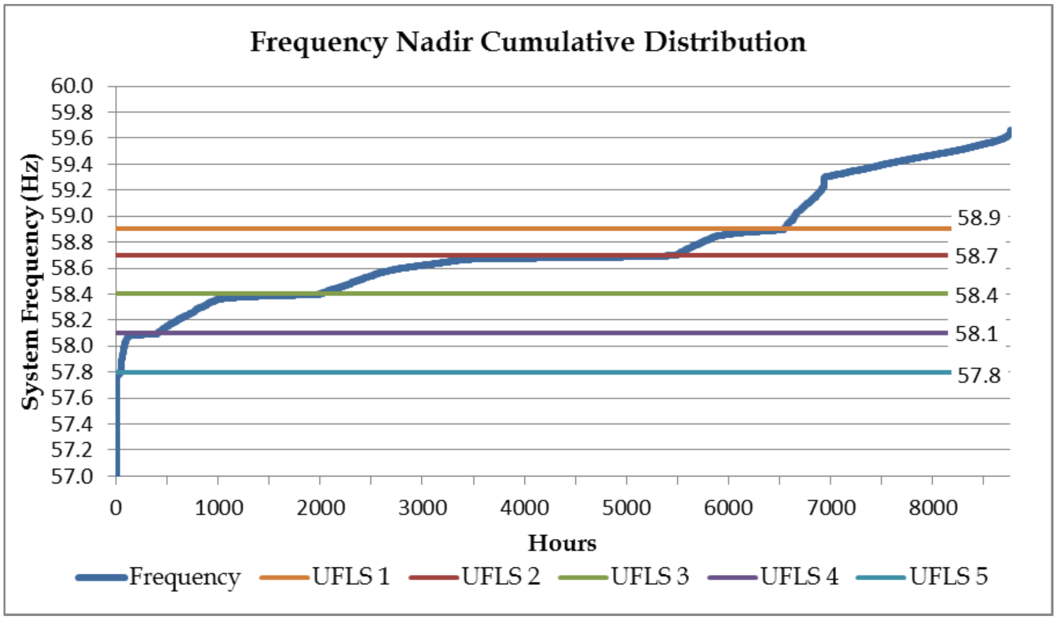

Figure O-182. Frequency Nadir Duration Curve 2030

Figure O-182 shows the frequency nadir duration curve for 2030. The system is at risk of UFLS for 6543 hours of the year.

Unit	Unit Ratings							DR - GE CT2 Trip Typical Mon 9/23/30 Hour 1			DR - GE CT1 Trip Boundary Wed 4/17/30 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0	42.0	4.0	17.0
HPOWER-2	22.5	10.0			3.41	42.1	144						
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	20.0	20.0	10.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11	4.0	4.0	2.0			
JBPHH 1	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8	16.7	0.1	10.0
JBPHH 2	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8	16.7	0.1	10.0
JBPHH 3	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 4	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 5	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 2	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 3	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 4	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 5	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335				84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467				66.1	0.9	37.1
GE-151CT2	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	82.6	1.4	40.6
GE-151ST2	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	63.3	3.7	34.3
GE-151CT3	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0			
GE-151ST3	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0			
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	2.3			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						31			72		
-Kahuku	30	0						6			24		
-Kawailoa	69	0						11			27		
-Na Pua Makani	24	0						6			21		
-CBRE Wind	10	0						2			0		
DG-PV	871	0						0			0		
Station PV	843	0						0			0		
Total Kinetic Energy								4276			3555		
Total Load								687			466		
Total Load Shifting								-5			-82		
Total Thermal Generation								661			475		
Total Renewable Generation								31			72		
Total Generation								692			548		
Excess Generation								0			0		
Total Up Regulation								35			30		
Total Down Regulation								366			256		
Total FFR2 Capacity								33			33		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-72. Unit Commitment and Dispatch 2030

Table O-72 shows the unit commitment and dispatch for the typical hour (9/23/30, 1:00 AM) and boundary hour (4/17/30, 3:00 AM).

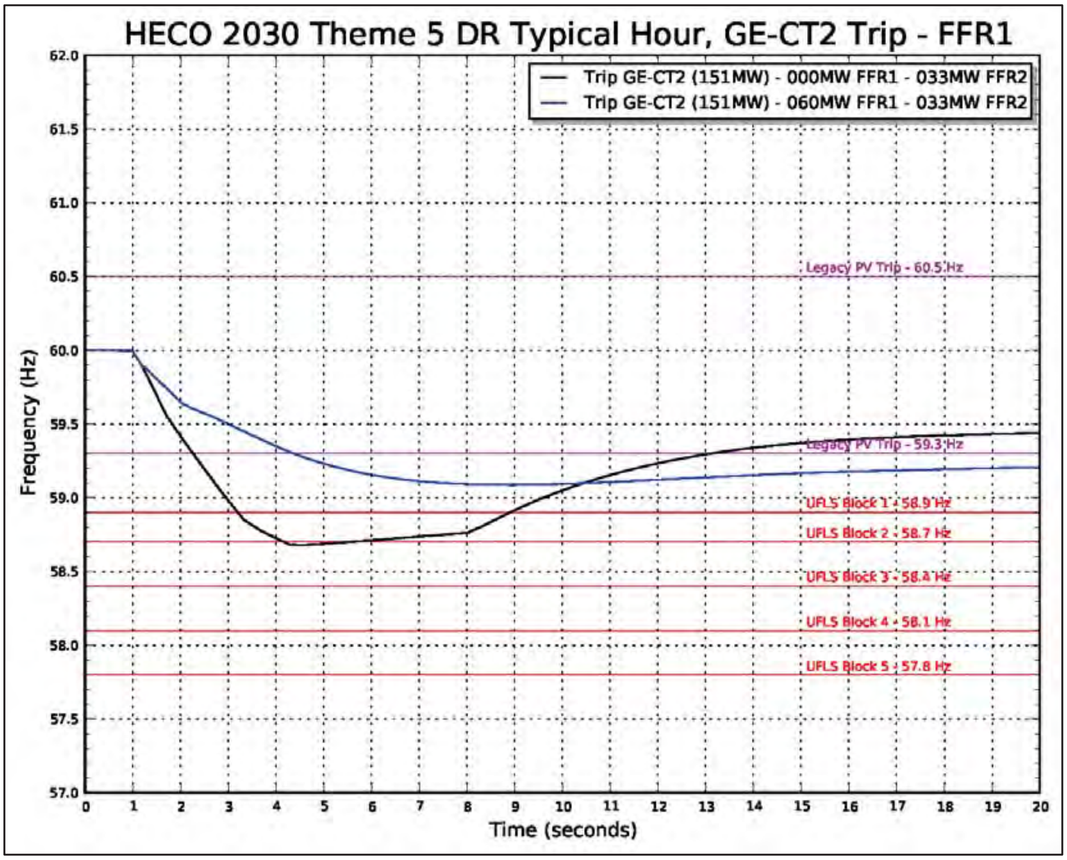

Figure O-183. Frequency Response Profile FFR1 Typical Hour

Figure O-183 shows the frequency response profile for a GE CT2 trip in combined-cycle operation for a typical hour. System kinetic energy is 4276 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 33 MW of FFR2.

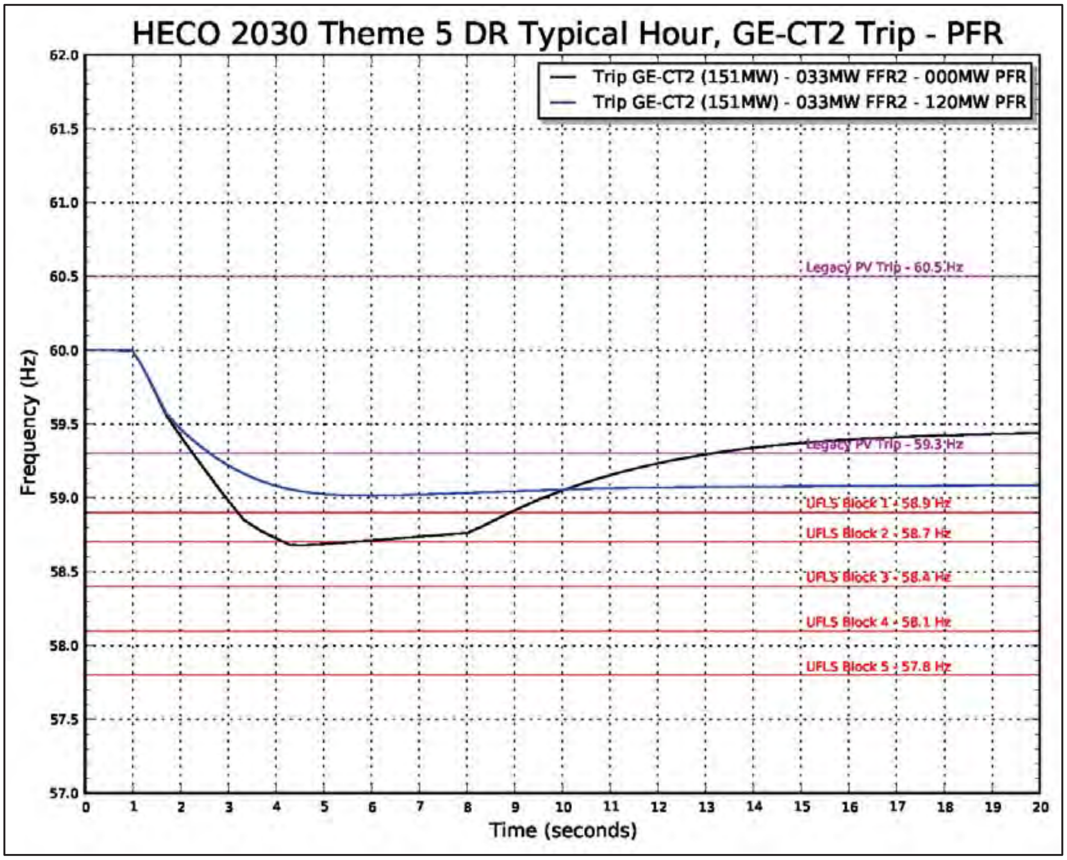

Figure O-184. Frequency Response Profile PFR Typical Hour

Figure O-184 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 120 MW. This is in addition to the 33 MW of FFR2 and 35 MW of upward regulation from thermal generation.

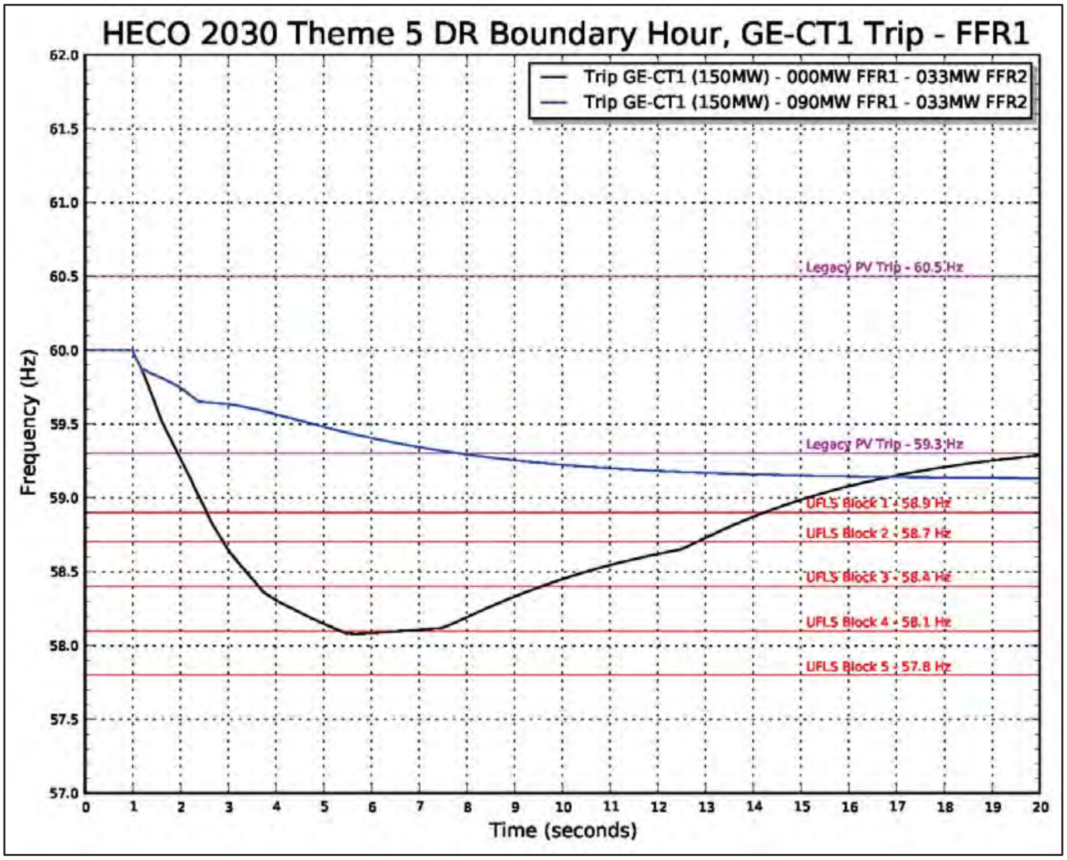

Figure O-185. Frequency Response Profile FFR1 Boundary Hour

Figure O-185 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3555 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 33 MW of FFR2.

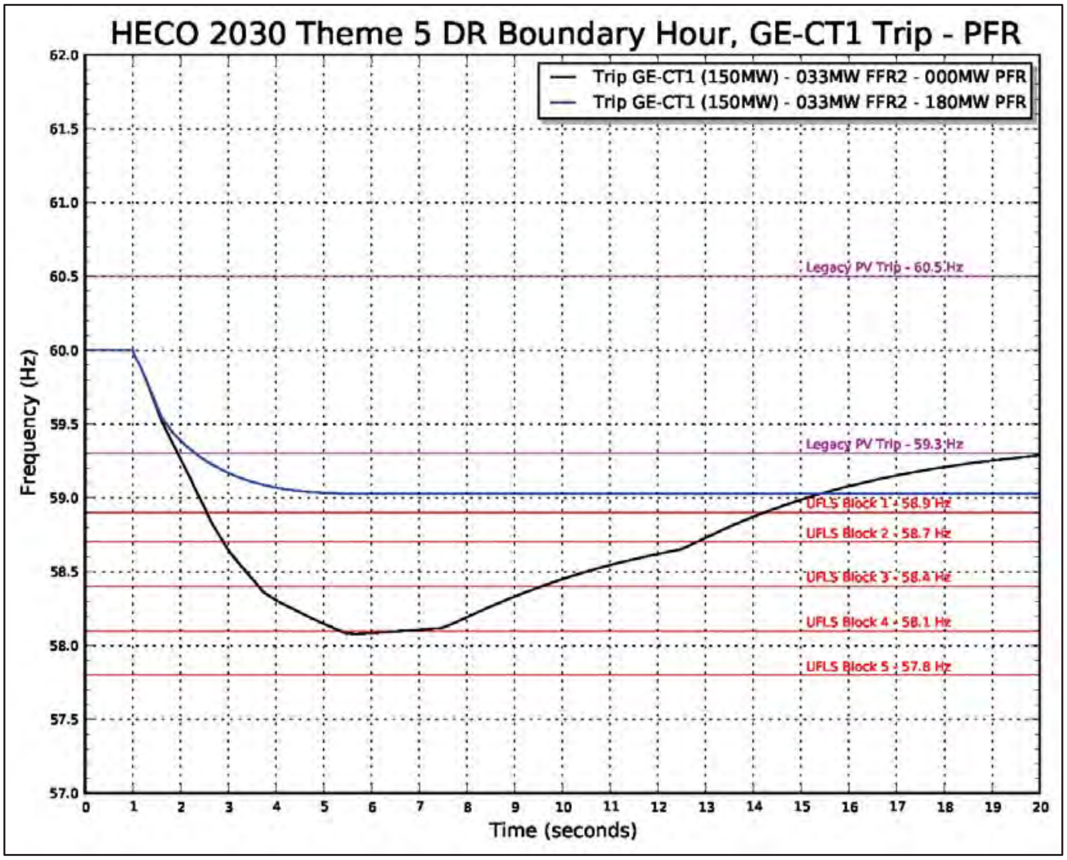

Figure O-186. Frequency Response Profile PFR Boundary Hour

Figure O-186 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 180 MW. This is in addition to the 33 MW of FFR2 and 30 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

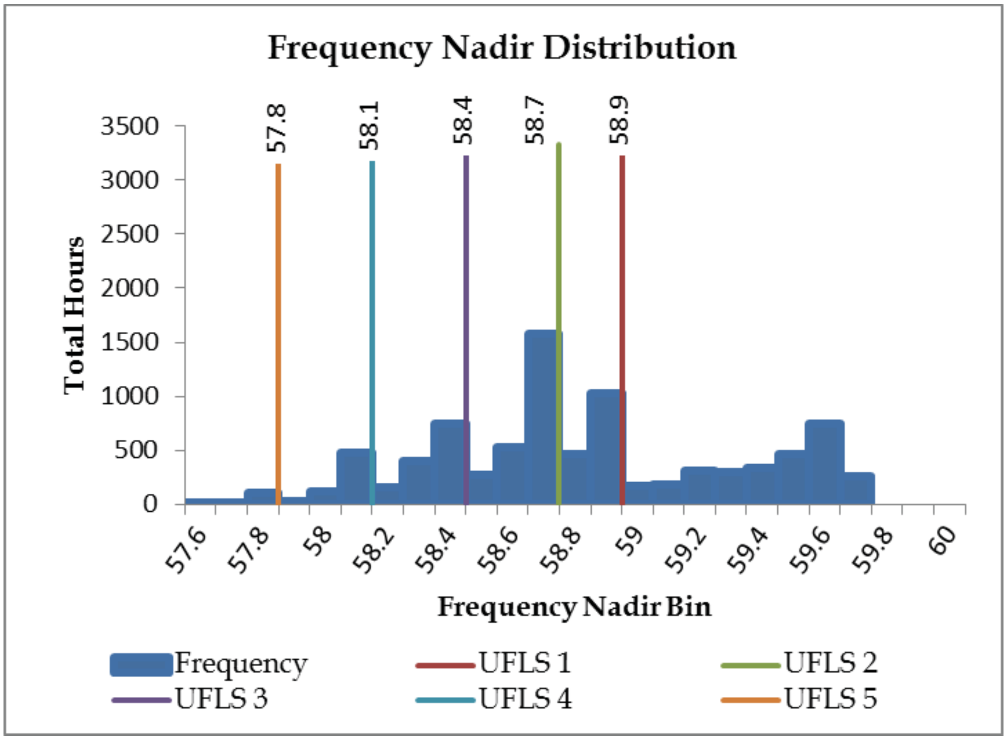

Figure O-187. Frequency Nadir Histogram 2045

Figure O-187 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 753 hours was 10:00 AM on Monday, January 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 22 hours was 5:00 AM on Sunday, October 22. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

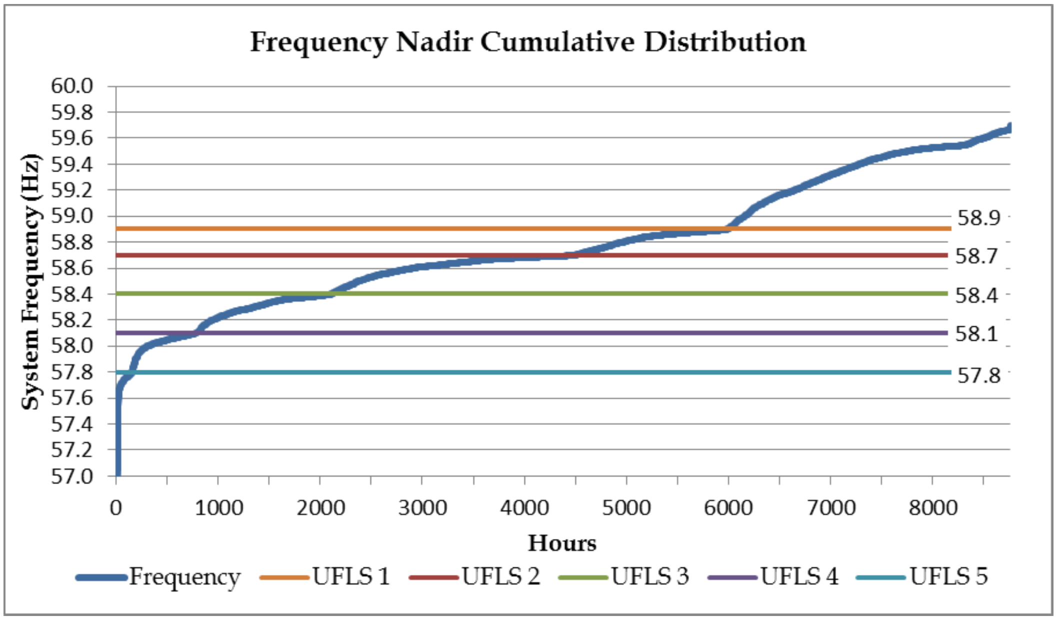

Figure O-188. Frequency Nadir Duration Curve 2045

Figure O-188 shows the frequency nadir duration curve for 2045. The system is at risk of UFLS for 5989 hours of the year.

Unit	Unit Ratings							DR - Off Shore Wind Trip Typical Mon 1/23/45 Hour 10			DR - Off Shore Wind Trip Boundary Sun 10/22/45 Hour 5		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335						
GE-151ST1	67.0	29.0			4.70	99.3	467						
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	-10.0			-10.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	963	0						654			599		
-Kahuku	30	0						5			4		
-Kawailoa	69	0						10			4		
-Na Pua Makani	24	0						0			8		
-CBRE Wind	10	0						2			1		
-Future Wind	30	0						0			0		
-Off Shore Wind	800	0						638			582		
DG-PV	1225	0						432			0		
Station PV	1043	0						120			0		
Total Kinetic Energy								1146			1002		
Total Load								1230			470		
Total Load Shifting								0			-154		
Total Thermal Generation								25			25		
Total Renewable Generation								1205			599		
Total Generation								1230			624		
Excess Generation								0			0		
Total Up Regulation								34			11		
Total Down Regulation								0			10		
Total FFR2 Capacity								48			40		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-73. Unit Commitment and Dispatch 2045

Table O-73 shows the unit commitment and dispatch for the typical hour (1/23/45, 10:00 AM) and boundary hour (10/22/45, 5:00 AM).

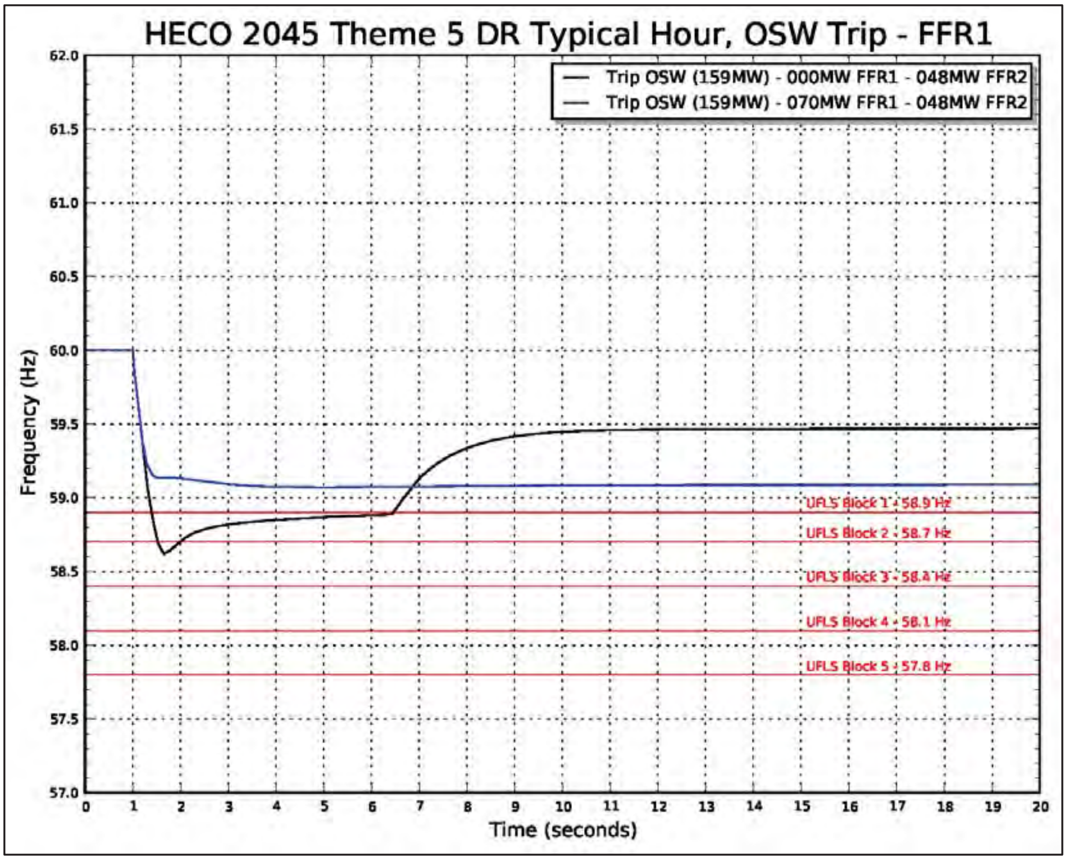

Figure O-189. Frequency Response Profile FFR1 Typical Hour

Figure O-189 shows the frequency response profile for an off-shore wind trip at 159 MW for a typical hour. System kinetic energy is 1146 MW-sec and the capacity of FFR2 is 48 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 48 MW of FFR2.

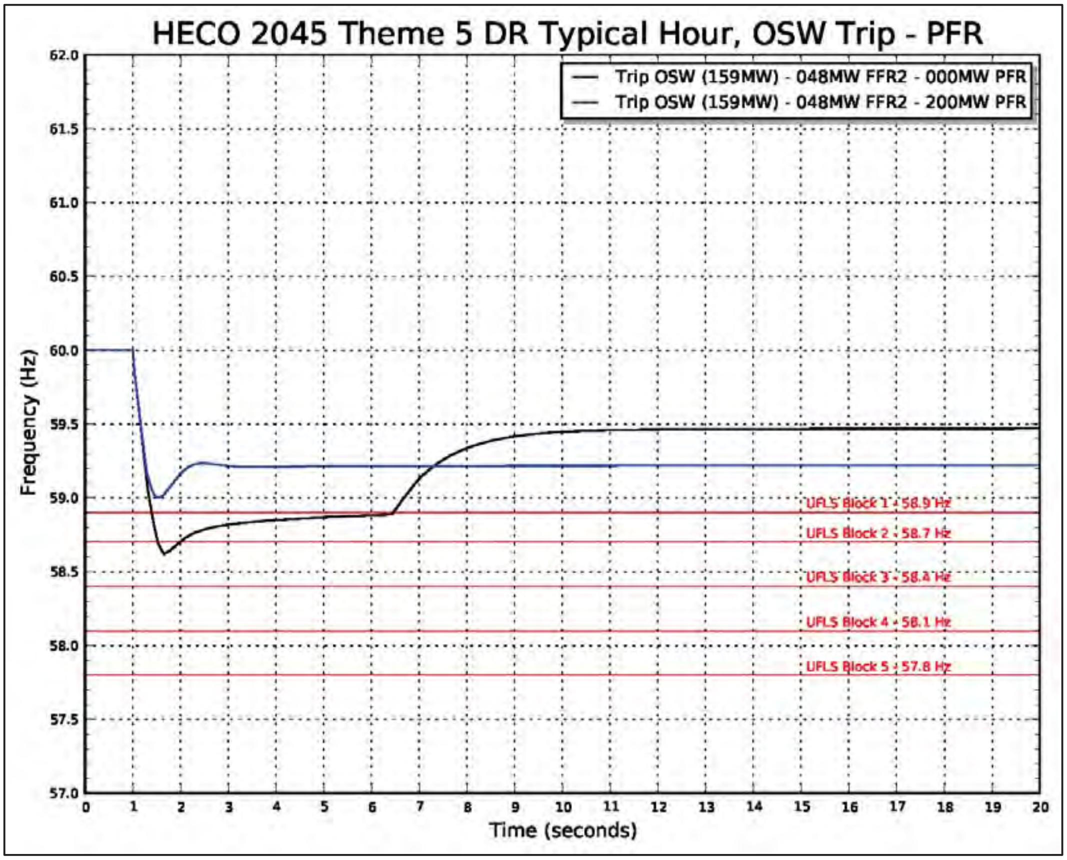

Figure O-190. Frequency Response Profile PFR Typical Hour

Figure O-190 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 48 MW of FFR2 and 34 MW of upward regulation from thermal generation.

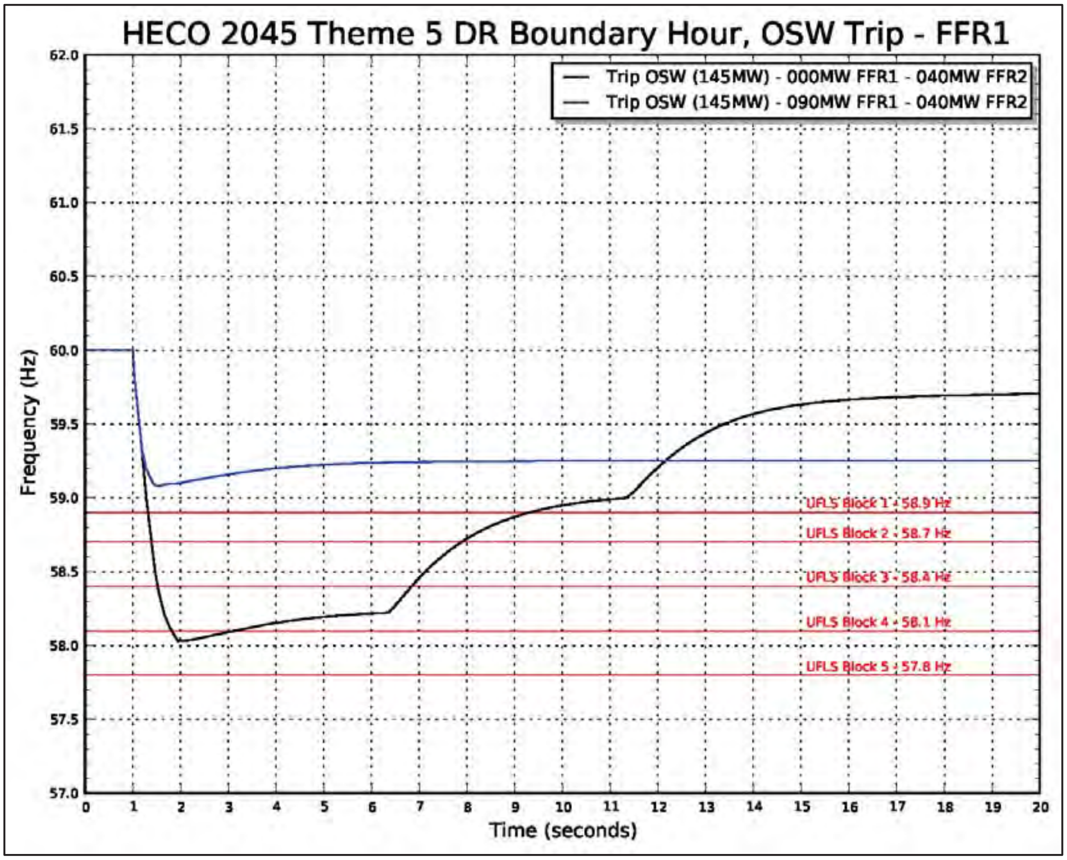

Figure O-191. Frequency Response Profile FFR1 Boundary Hour

Figure O-191 shows the frequency response profile for the FFR1 analysis. System kinetic energy is 1002 MW-sec and the capacity of FFR2 is 40 MW. With no additional FFR, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 40 MW of FFR2.

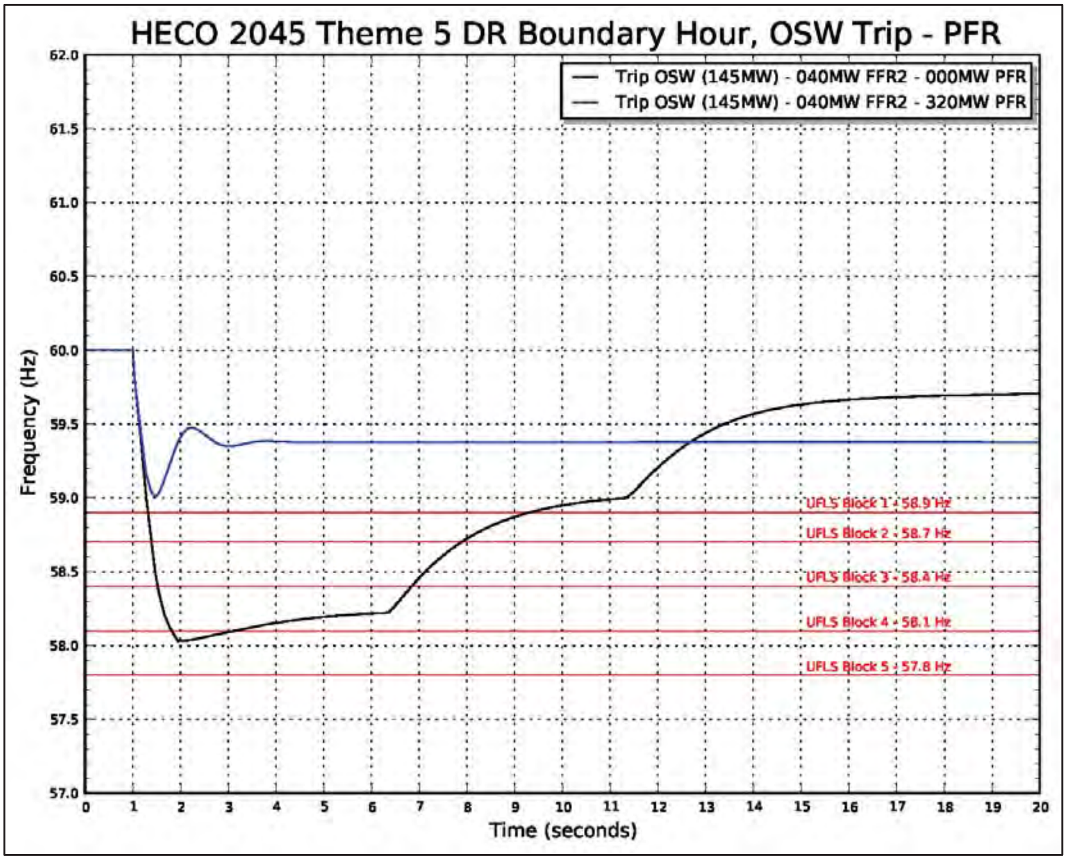

Figure O-192. Frequency Response Profile PFR Boundary Hour

Figure O-192 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 320 MW. This is in addition to the 40 MW of FFR2 and 11 MW of upward regulation from thermal generation.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on two plans; 1) No LNG; High DG-PV plan and 2) No LNG, High DG-PV; Power Supply Retirement plan.

E3 - No LNG; High DG-PV

- QV Analysis (2019 – 2021): Conversion of Honolulu 8 and 9 to synchronous condensers is required in 2020.
- Loss of Generation Analysis (2019 – 2020): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 138 kV Fault Analysis (2019 – 2020): All normally cleared faults were stable with multiple blocks of UFLS. System performance is similar to the Post April DR plan.

E3 - No LNG; High DG-PV; Power Supply Retirements

- QV Analysis (2019 – 2021): Conversion of Honolulu 8 and 9 to synchronous condensers is not required in the 5-year action plan period.
- Loss of Generation Analysis (2019 – 2020): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 138 kV Fault Analysis (2019 – 2020): All normally cleared faults were stable with multiple blocks of UFLS. System performance is similar to the Post April DR plan.

O‘ahu Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

The O‘ahu system does not meet the requirements of TPL-001. Based on historical data, an AES trip at full output requires multiple blocks of UFLS to help stabilize system frequency. Analysis was performed for 2019 to determine capacities of frequency response reserves to mitigate an AES trip at full capacity and a Kahe Unit 5 trip at full capacity.

The O‘ahu system may also be susceptible to system collapse for a normally cleared three-phase fault because of the proliferation of DG-PV. An electrical fault is the most severe disturbance on the transmission system typically characterized by high system frequency and low voltages. During a fault, system voltage can be suppressed below the 0.5 PU voltage ride-through threshold of inverter-based generation, momentarily tripping the entire capacity of DG-PV from the system. If system voltage does not recover within the 0.5-second ride-through time, inverters will disconnect from the system.

If the capacity of DG-PV is high, the momentary loss of power could drive system frequency below 57.0 Hz and initiate under-frequency protection for synchronous generators. Inverter-based generation will also trip at 56.0 Hz.

Analyzing DG-PV performance during transmission faults requires a dynamic 3-phase model from the transmission system to the distribution system so single-phase distribution system voltages can be accurately simulated. Complex load models must also be developed since load characteristics will impact transient voltage stability.

Potential mitigating strategies include the following:

Limit the area of impact. The O‘ahu system is more vulnerable to system collapse when central station generation is concentrated on the Leeward side of the island because a three-phase fault between Leeward O‘ahu and Honolulu basically syncs the system's voltage source to ground. Sensitivity analysis indicates that running synchronous units at Waiau limits the number of transmission circuit faults that will collapse the system. Mitigation strategies at the distribution system should also be evaluated.

Increase the magnetic strength of the system. Transient voltage stability is maintained by increasing the short circuit current capacity on the transmission system. Short circuit ratio analysis should be performed for each critical bus to ensure voltage stability. The synchronous condenser requirements established in this PSIP only ensures that the protective relays will operate and the system's reactive power requirements for each resource plan is met; it doesn’t ensure transient voltage stability.

Add frequency response reserves. Frequency response reserves can help stabilize system frequency for both the momentary loss of DG-PV, and the ultimate trip of all DG-PV. As stated above, at some point in time the capacity of DG-PV will be too high and frequency response reserves will be too costly or ineffective.

Improve inverter performance. The inverter industry is in the best position to mitigate this problem. Under-voltage ride-through requirements are nebulous; presently defined as "Permissive Operation" where the inverter manufacturer must remain connected to the grid but inverter output current can range from zero to full output.

Minimum Fault Current

Minimum fault current analysis was performed for the April PSIP. For O‘ahu, 515 MVA at the 138 kV system is required. This ensures protective relay schemes will operate but this does not ensure transient voltage stability is maintained.

QV Analysis

The O‘ahu transmission system is designed to operate with two transmission lines out of service (N-2) while maintaining a minimum bus voltage of 0.92 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide fault current to meet the minimum 515 MVA requirement. Therefore, only synchronous condensers are evaluated in these analyses.

For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

For the Theme 5 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. For the 5-year action plan period, sensitivity analysis was performed for a Kahe Unit 5 trip at full capacity. Table O-201 (page O-615) shows the results of the analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW for an AES trip and 90 MW for a Kahe 5 trip.

For the Post April DR resource plan, hourly capacities of FFR2 were provided to augment frequency response reserves. Analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Similar to the Theme 5 analysis, sensitivity analysis was performed for a Kahe Unit 5 trip at full capacity. Table O-202 (page O-615) shows the results of the analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW for an AES trip and 30 MW for a Kahe 5 trip.

138 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019. Breaker failure analysis produced similar results.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Strategies that were analyzed include 1) mitigate the loss of generation with the addition of PFR at 1% droop response, and 2) limit transient voltage impact by committing Waiau 7 and 8 in VPO. Both of these strategies improved system performance. Table O-74 shows the results of the PFR analysis to bring the system into compliance with TPL-001.

Year	PFR (MW)	
	No DR	DR
2019	440	350
2020	550	420
2021	740	440

Table O-74. Summary of Results PFR Analysis

Further analysis is required to determine optimal mitigating strategies to maintain system security.

MAUI SYSTEM SECURITY ANALYSIS

State of the System

The Maui system does not meet the requirements of TPL-001. Maui has three wind plants that total 72 MW that displaces synchronous generation. Maui operates with the minimum must-run units for the most of the year.

Analyses was conducted to evaluate the Maui system to determine technology-neutral system security requirements to maintain system stability and meet TPL-001.

Minimum Fault Current

A minimum fault current analysis was not performed for this PSIP. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Maui transmission system requires 72 MVA on the 69 kV system and 30 MVA on the 23 kV system. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

Historical Contingency Events

On March 1, 2012, the system experienced the loss of two Ma'alaea generating units that tripped offline. The total system generation prior to the event was 155 MW. Ma'alaea M16 generating unit breaker opened at 13:32:35 with an output of 19.7 MW. The frequency decreased to 58.4 Hz and tripped Block 1 & 2 on UFLS for the frequency to recover. After a short recovery, M19 tripped offline with an output of 20.2 MW. The loss of M19 decreased the frequency to 57.7 Hz and triggered Block 3 on UFLS.

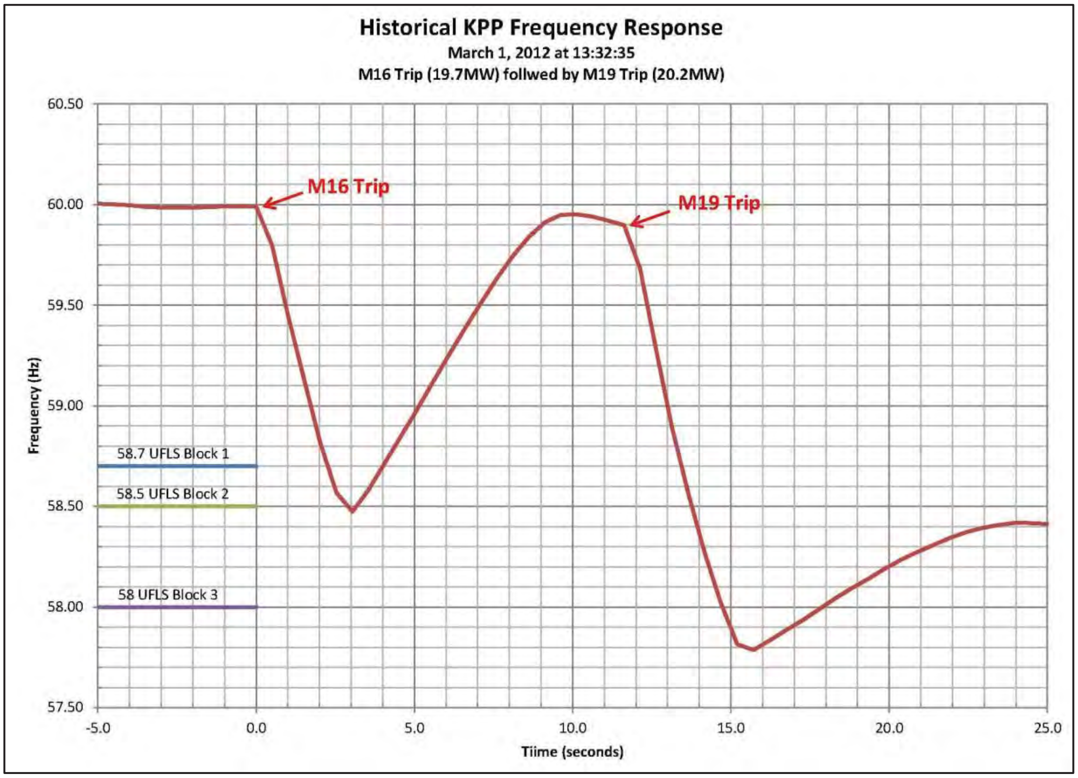

Figure O-193. Frequency Response Profile for Historic Events

Figure O-193 shows the frequency response profile for the M16 and M19 trip. The M16 trip causes the frequency nadir to breach 58.5 Hz that required 2 blocks of UFLS to stabilize system frequency.

2017

Loss of Generation Simulation

System security analysis was performed on two hours that were selected from the Theme 3 (a no-LNG case) production cost simulations that represents a typical hour and a boundary condition.

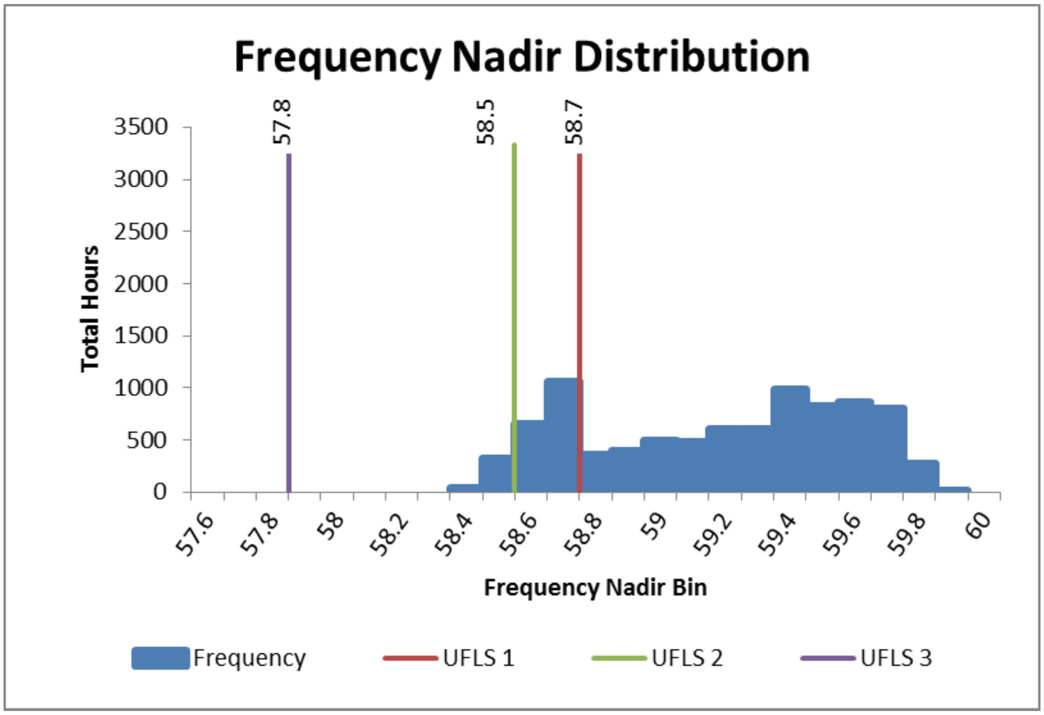

Figure O-194. Frequency Nadir Histogram 2017

Figure O-194 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2017. The typical hour selected from the maximum distribution of 323 hours was2:00 PM on Wednesday, June 17. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 44 hours was 4:00 AM on Friday, September 1. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

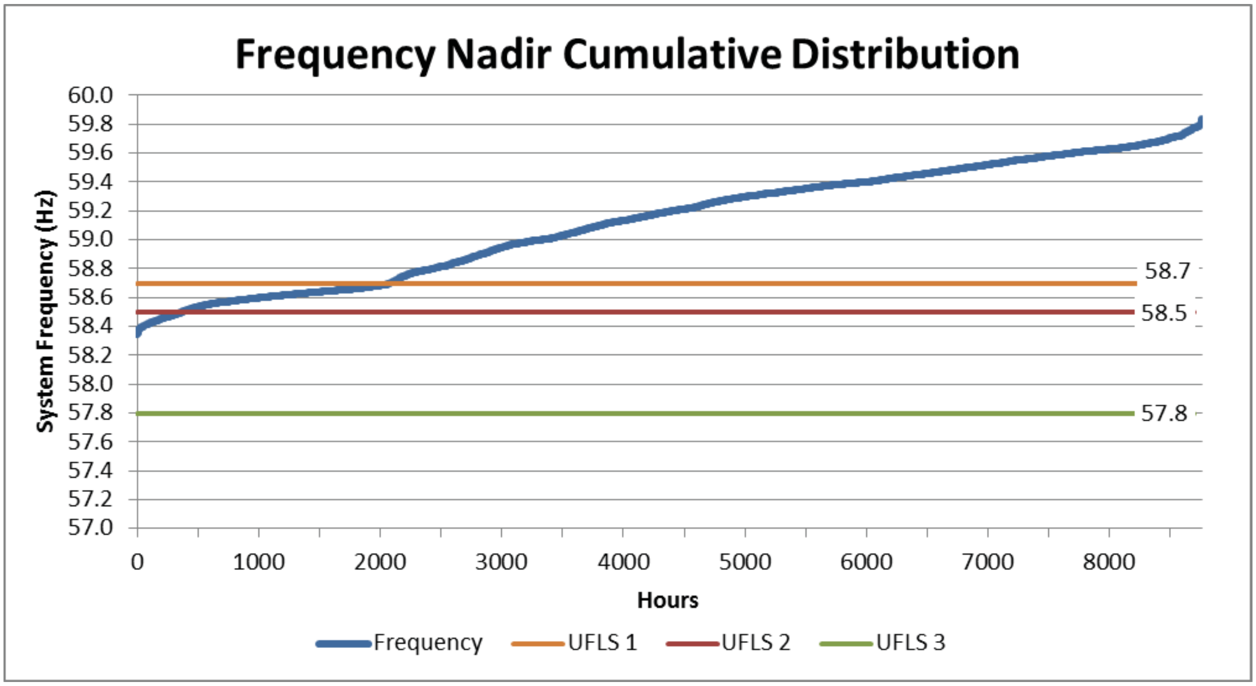

Figure O-195. Frequency Nadir Distribution Curve 2017

Figure O-195 shows the frequency nadir duration curve for 2017. The system is at risk of exceeding the UFLS requirements of TPL-001 for 367 hours of the year.

Unit	Unit Ratings					Current System - KWP I Trip Typical Wed 6/7/2017 Hour 14			Current System - KWP I Trip Boundary Fri 9/1/2017 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	10.0	1.5	7.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0			
Maalaea 14	20.0	5.9	2.02	26.8	58	11.6	8.4	5.7	7.5	12.5	1.6
Maalaea 15	13.0	3.0	2.46	18.5	46	4.4	8.6	1.4	5.0	8.0	2.0
Maalaea 16	20.0	5.9	2.02	26.8	54				7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54				19.5	0.0	13.6
Maalaea 18	12.8	3.0	2.46	18.5	46				7.5	5.3	4.5
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Total Wind	72					72			51		
-KWP	30	0				30			30		
-Auwahi	21	0				21					
-KWPII	21	0				21			21		
Central PV	5.74	0				5					
DG-PV	113	0				84					
Total System MVA							76			133	
Total Kinetic Energy							246			346	
Total Load							185			110	
Total Thermal Generation							26			57	
Total Renewable Generation							161			51	
Total Generation							187			108	
Excess Generation							2			-2	
Regulation Requirement							0			0	
Total Up Regulation							30			40	
Total Down Regulation							11			23	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.4	59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		51.6	60.5Hz Output		0.0

Table O-75. Unit Commitment and Dispatch 2017

Table O-75 shows the unit commitment and dispatch schedules for the typical hour (6/7/17, 2:00 PM) and boundary hour (9/1/17, 4:00 AM).

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For Maui, the largest loss of generation contingency is a KWP I trip at 30 MW.

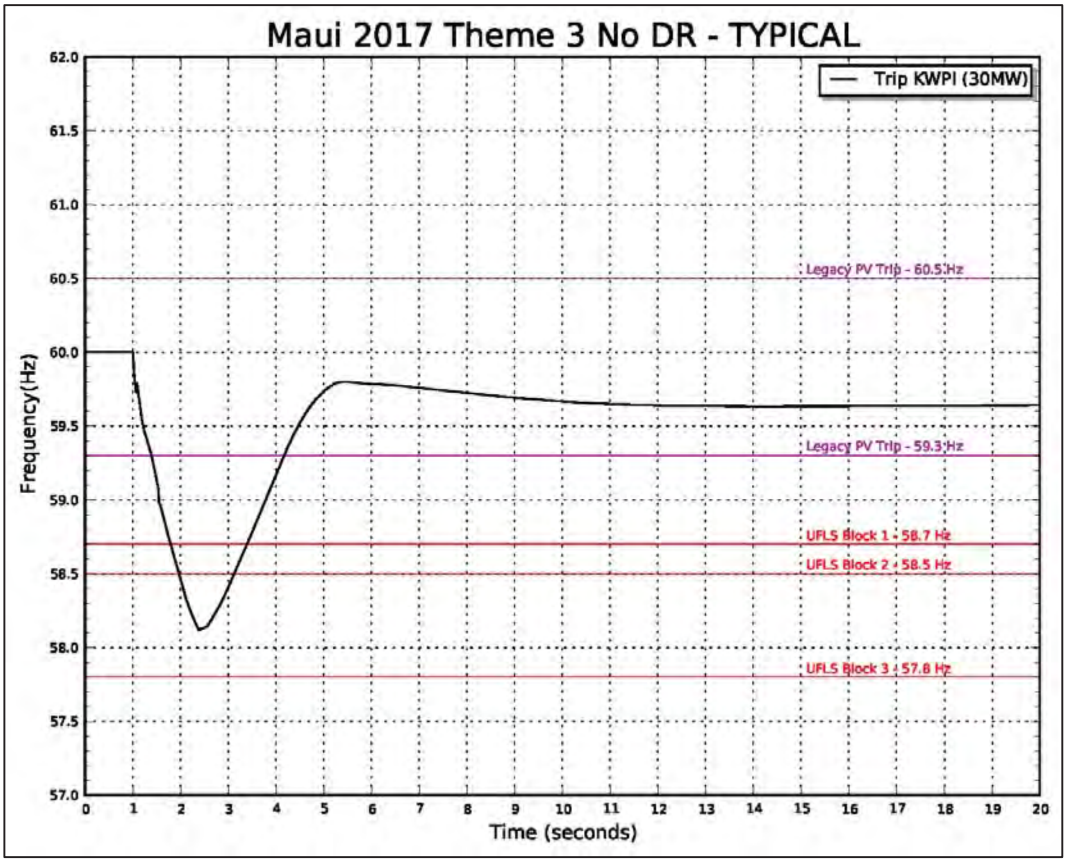

Figure O-196. Frequency Response Profile Typical Hour

Figure O-196 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 246 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.4 MW. The frequency nadir is 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The system is not in compliance with TPL-001.

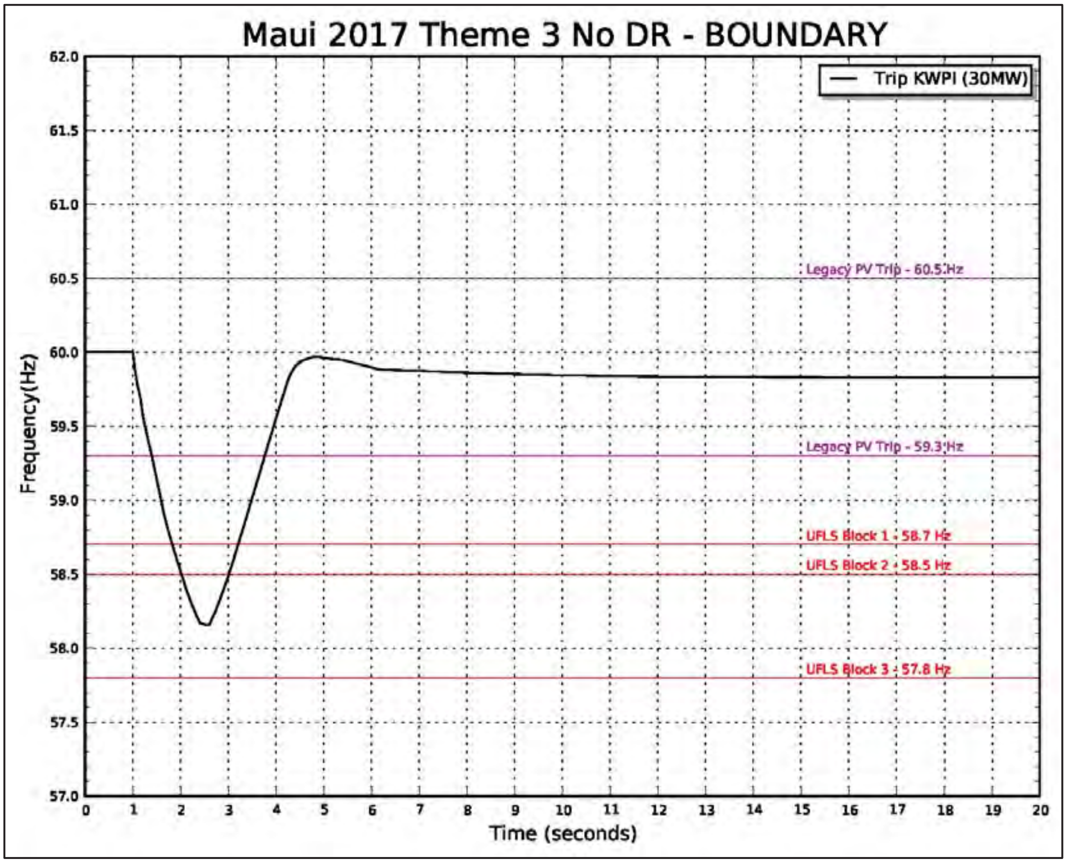

Figure O-197. Frequency Response Profile Boundary Hour

Figure O-197 shows the frequency response profile for the boundary hour. The frequency nadir is 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The system is not in compliance with TPL-001.

69 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. For Maui, normally cleared faults are isolated in 5-cycles at the near end and up to 30-cycles at the far end. Therefore, a normally cleared fault at the far end of the circuit constitutes a delayed clearing fault.

Unit	Unit Ratings					Current System - Fault Dispatch Thu 6/1/2017 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	11.6	8.4	5.7
Maalaea 15	13.0	3.0	2.46	18.5	46	4.4	8.6	1.4
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54	12.3	7.3	6.4
Maalaea 18	12.8	3.0	2.46	18.5	46	4.3	8.5	1.3
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					38		
-KWP	30	0				8		
-Auwahi	21	0				17		
-KWPII	21	0				13		
Central PV	5.74	0						
DG-PV	113	0				97		
Total System MVA						122		
Total Kinetic Energy						346		
Total Load						179		
Total Thermal Generation						43		
Total Renewable Generation						135		
Total Generation						178		
Excess Generation						-1		
Regulation Requirement						0		
Total Up Regulation						46		
Total Down Regulation						19		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		6.2
	60.5Hz Capacity			69.5		60.5Hz Output		59.6

Table O-76. Unit Commitment and Dispatch Fault Analysis 2017

Table O-76 shows the unit commitment and dispatch for the 69 kV fault analysis (6/1/17, 12:00 PM). Inverter-based generation is 97 MW.

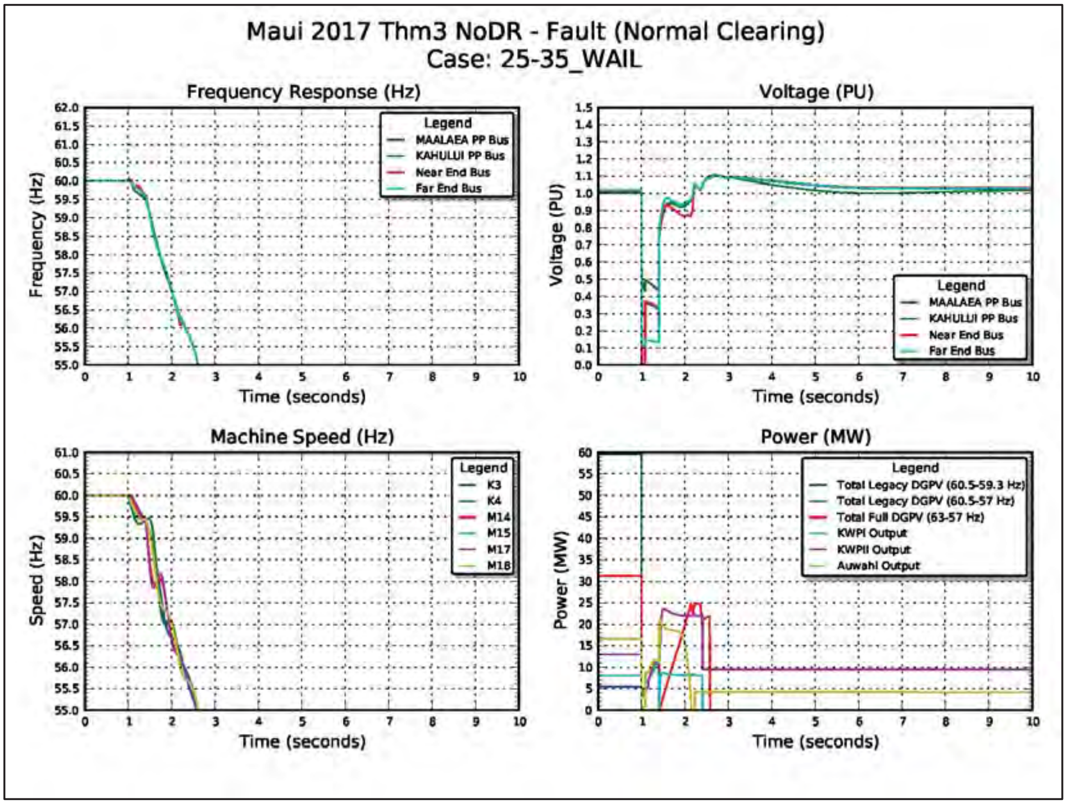

Figure O-198. System Performance for Normally Cleared Fault

Figure O-198 shows the system performance for a normally cleared fault at the Wailea end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 97 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Maui 2019 Theme 3 No DR Fault Analysis		
Line	3-phase Fault Near	System Status
		Normal Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable
	Waiinu	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable
	Kanaha	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable
	Waiinu	Stable
Wailea-Kihei 69kV	Wailea	Unstable
	Kihei	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable
	Lahainaluna	Unstable
MPP-Kihei 69kV	MPP	Stable
	Kihei	Stable
MPP-Waiinu 69kV	MPP	Stable
	Waiinu	Unstable
MPP-Puunene 69kV	MPP	Stable
	Puunene	Unstable
MPP-KWPII 69kV	MPP	Stable
	KWPII	Stable
MPP-KWP 69kV	MPP	Stable
	KWP	Stable
MPP-Lahainaluna 69kV	MPP	Stable
	Lahainaluna	Stable
MPP-Kula AG 69kV	MPP	Stable
	Kula AG	Unstable
Kealahou-Kula 69kV	Kealahou	Stable
	Kula	Unstable
Kealahou-Kula AG 69kV	Kealahou	Unstable
	Kula AG	Unstable
KPP-Kanaha FDR1 23kV	KPP	Stable
	Kanaha FDR1	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable
	Kanaha FDR2	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable
	Kanaha FDR3	Stable
KPP-Wailuku 23kV	KPP	Stable
	Wailuku	Stable
Kanaha-Puunene 23kV	Kanaha	Stable
	Puunene	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable
	Pukalani	Unstable
Kanaha-Puunene 69kV	Kanaha	Stable
	Puunene	Stable
Kula-Pukalani 69kV	Kula	Stable
	Pukalani	Stable

Table O-77. Summary of Results Fault Simulation

Table O-77 is the summary of results for the breaker failure analysis. Fifteen simulations resulted in system instability where system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip.

Post April No DR Plan –Theme 3

System security analysis performed on the Theme 3 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 3 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Maui transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirements of 73 MVA on the 69 kV system and 29 MVA on the 23 kV system. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Mon 12/30/2019 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	11.5	0.0	8.5
Kahului 4	11.5	3.0	3.48	15.6	54	10.4	1.2	7.4
Maalaea 14	20.0	5.9	2.02	28.8	58	20.0	0.0	14.1
Maalaea 15	13.0	5.0	2.46	18.5	46	13.0	0.0	8.0
Maalaea 16	20.0	5.9	2.02	26.8	54	20.0	0.0	14.1
Maalaea 17	19.5	5.9	2.02	26.8	54	19.5	0.0	13.6
Maalaea 18	12.8	3.0	2.46	18.5	46	13.6	-0.8	10.6
Maalaea 19	19.5	5.9	2.02	26.8	54	19.5	0.0	13.6
Maalaea 10	12.3	7.9	3.28	15.6	51	12.2	0.1	4.3
Maalaea 12	12.3	7.9	3.28	15.6	51	12.2	0.1	4.3
Maalae13	12.3	7.9	3.28	15.6	51	12.3	0.0	4.5
Maalaea 11	12.3	7.9	3.28	15.6	51	12.1	0.2	4.2
Maalaea 4	5.5	1.9	2.28	7.0	16	4.0	1.5	2.1
Maalaea 6	5.5	1.9	2.28	7.0	16	4.4	1.1	2.6
Maalaea 9	5.5	1.9	2.28	7.0	16	3.8	1.7	2.0
Maalaea 8	5.5	1.9	2.28	7.0	16	4.4	1.1	2.5
Maalaea 5	5.5	1.9	2.28	7.0	16	4.4	1.1	2.6
Maalaea 1	2.5	2.3	0.83	3.4	3	2.3	0.3	0.0
Maalaea 3	2.5	2.5	0.83	3.4	3	2.5	0.0	0.0
Maalaea 2	2.5	2.5	0.83	3.4	3	2.5	0.0	0.0
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	4.7	0.3	4.7
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					0		
-KWP	30	0						
-Auwahi	21	0						
-KWPII	21	0						
DG-PV	121	0						
DER Grid Ex	4.2	0						
Total System MVA						289		
Total Kinetic Energy						764		
Total Load						209		
Total Thermal Generation						209		
Total Renewable Generation						0		
Total Generation						209		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						8		
Total Down Regulation						103		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0

Table O-78. Unit Commitment and Dispatch 2019 QV Analysis

Table O-78 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Mon 12/30/2019 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	4.0	0.2	4.0
Maalaea 15	2.9	0.0	1.4	1.5	1.4
Maalaea 16	4.1	0.0	1.4	2.7	1.4
Maalaea 17	15.0	0.0	1.4	13.6	1.4
Maalaea 18	12.0	0.0	1.4	10.6	1.4
Maalaea 19	15.0	0.0	1.4	13.6	1.4
Maalaea 10	9.4	0.0	0.0	9.4	0.0
Maalaea 12	9.4	0.0	0.7	8.7	0.7
Maalaea13	9.4	0.0	0.7	8.7	0.7
Maalaea 11	2.0	0.0	0.0	2.0	0.0
Maalaea 4	4.2	0.0	0.2	4.0	0.2
Maalaea 6	4.2	0.0	0.5	3.7	0.5
Maalaea 9	4.2	0.0	0.4	3.8	0.4
Maalaea 8	4.2	0.0	0.2	4.0	0.2
Maalaea 5	4.2	0.0	0.2	4.0	0.2
Maalaea 1	1.9	0.0	0.2	1.7	0.2
Maalaea 3	1.9	0.0	0.2	1.6	0.2
Maalaea 2	1.9	0.0	0.2	1.6	0.2
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0	0.0	3.0	0.0
Kahului 2	3.0	0.0			
Total Wind	31.2	0.0			
-KWP	14.5	-0.2			
-Auwahi	6.5	-6.5			
-KWPII	10.2	0.0			
DG-PV	0.0	0.0			
Total Thermal MVAR Generation			14.6		
Total Renewable MVAR Generation			0.0		
Total Cap Bank MVAR			54.4		
Charging MVAR			5.3		
Total MVAR Supply			74.4		
Total MVAR Load			33.0		
Total MVAR Losses			41.3		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				115	
Total MVAR Absorb Capability					14.6

Table O-79. MVAR Capability 2019 QV Analysis

Table O-79 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu

Table O-80. N-1 Contingencies 2019 QV Analysis

Table O-80 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

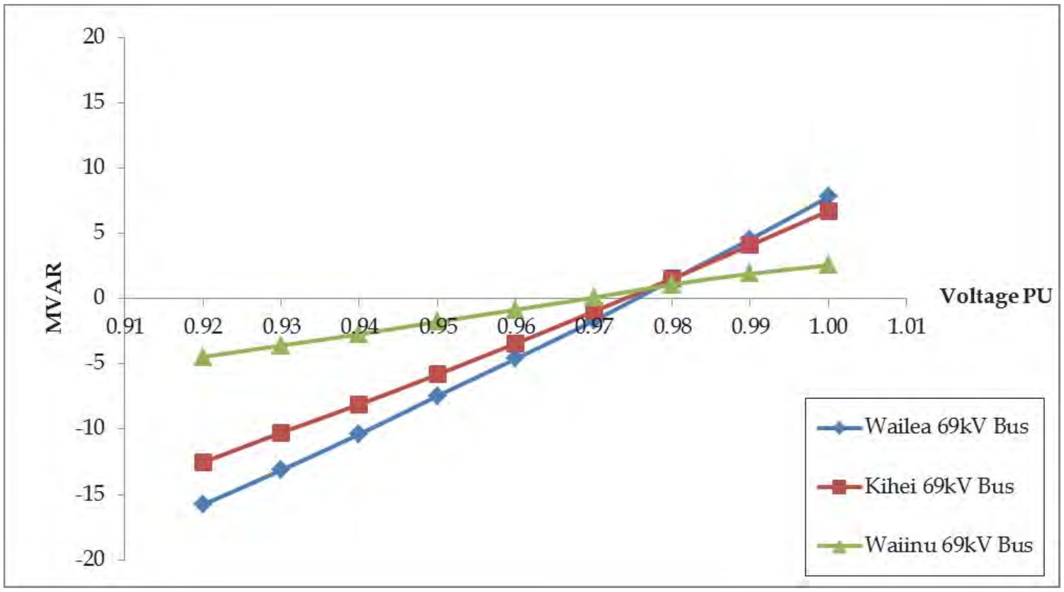

Figure O-199. QV Curves 2019

Figure O-199 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	102	8	102	5	102	1	102	-2	102	-5	102	-7	102	-10	102	-13	102	-16
35	Kihei 69 kV Bus	102	7	102	4	102	2	102	-1	102	-3	102	-6	102	-8	102	-10	102	-13
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-4

Table O-81. Summary of Results 2019 QV Analysis

Table O-81 shows the results of the QV analysis for 2019. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

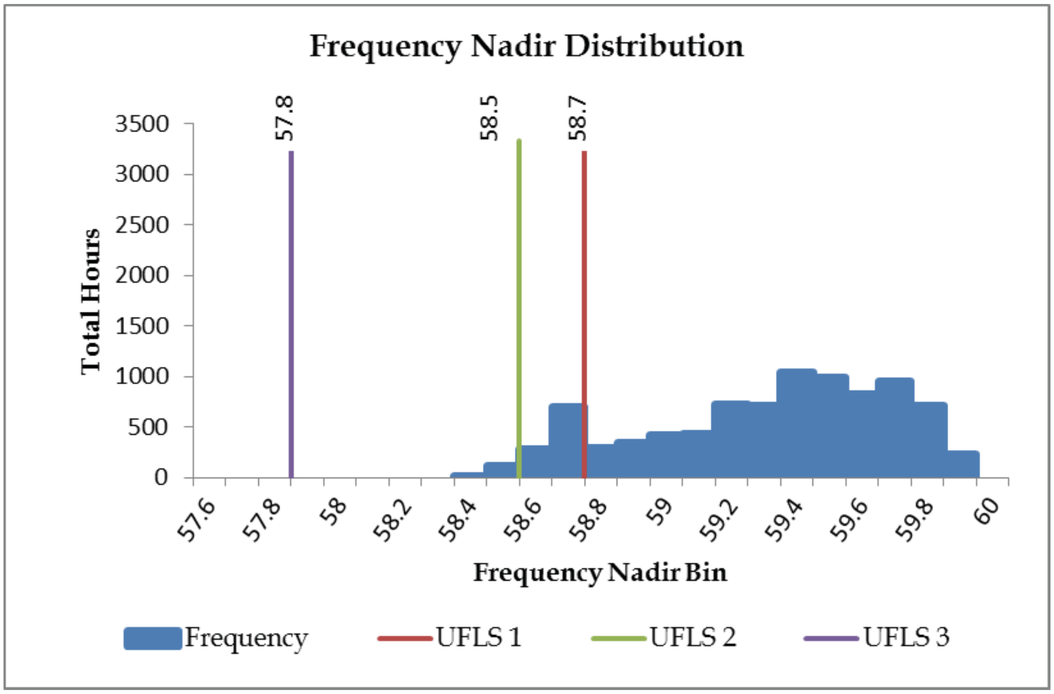

Figure O-200. Frequency Nadir Histogram for 2019

Figure O-200 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 211 hours was 1:00 PM on Friday, March 22. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 8 hours was 2:00 PM on Sunday, March 17. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

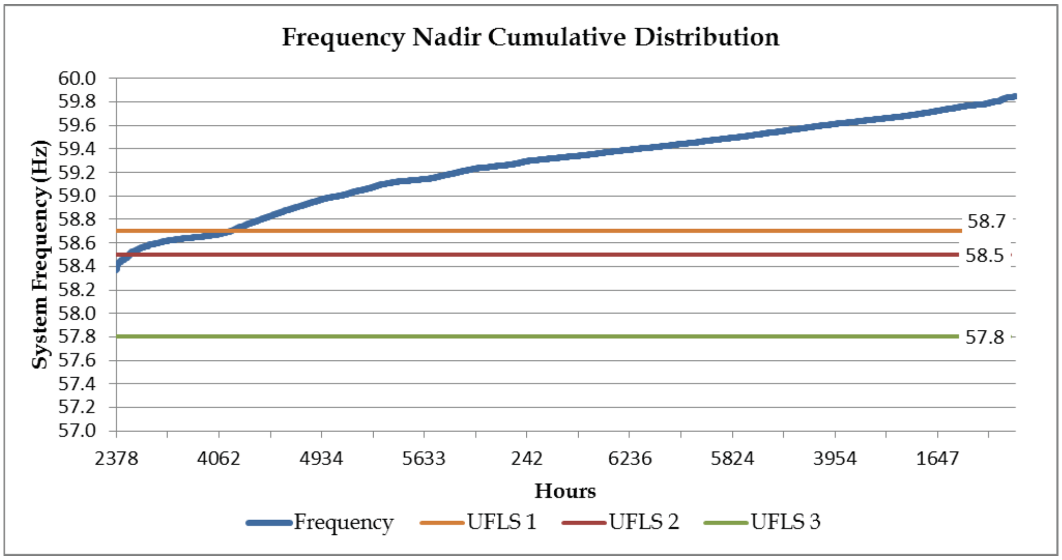

Figure O-201. Frequency Nadir Duration Curve 2019

Figure O-201 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 8 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Fri 3/22/2019 Hour 13			Theme 3 - KWP I Trip Boundary Sun 3/17/2019 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	7.5	12.5	1.6	7.5	12.5	1.6
Maalaea 15	13.0	5.0	2.46	18.5	46	5.0	8.0	0.0	5.0	8.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Total Wind	72					233%	49		63%	45	
-KWP	30	0					29			30	
-Auwahi	21	0								2	
-KWPII	21	0					20			13	
DG-PV	121	0				79%	96		76%	92	
DER Grid Ex	4.2	0				71%	3		71%	3	
Total System MVA							101			101	
Total Kinetic Energy							300			300	
Total Load							177			169	
Total Thermal Generation							30			30	
Total Renewable Generation							148			140	
Total Generation							178			170	
Excess Generation							1			1	
Regulation Requirement							0			0	
Total Up Regulation							33			33	
Total Down Regulation							3			3	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		5.7	59.3Hz Output		5.5
		60.5Hz Capacity		69.5		60.5Hz Output		55.1	60.5Hz Output		52.8

Table O-82. Unit Commitment and Dispatch 2019

Table O-82 shows the unit commitment and dispatch for the typical hour (3/22/19, 1:00 PM) and boundary hour (3/17/19, 2:00 PM).

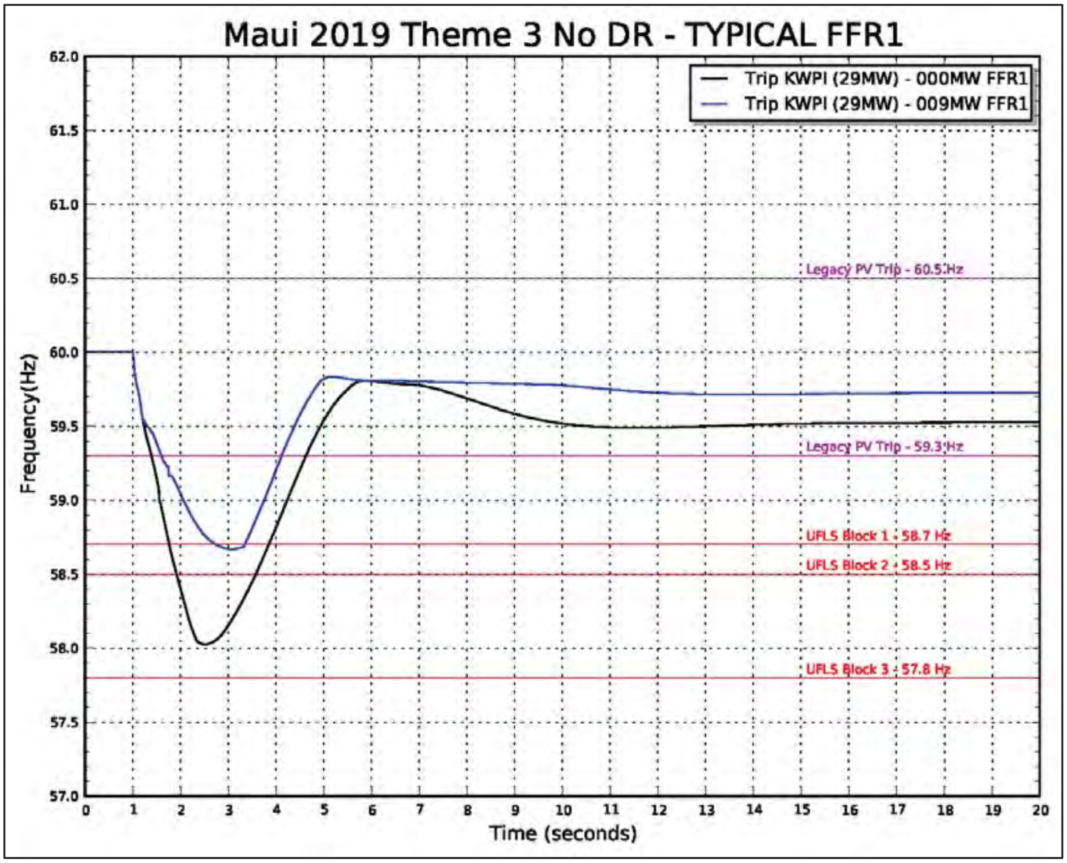

Figure O-202. Frequency Response Profile for FFR1 Typical Hour

Figure O-202 shows the frequency response profile for a KWP I trip at 29 MW for a typical hour. System kinetic energy is 300 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.7 MW. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

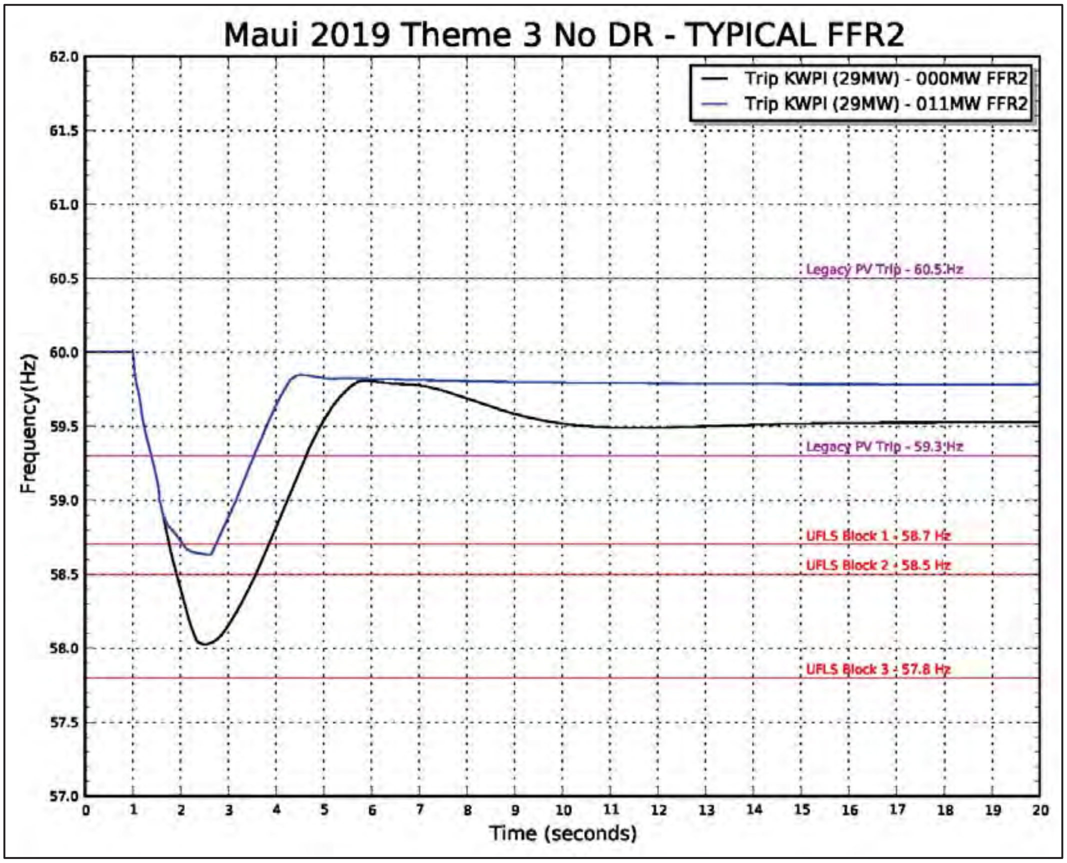

Figure O-203. Frequency Response Profile for FFR2 Typical Hour

Figure O-203 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

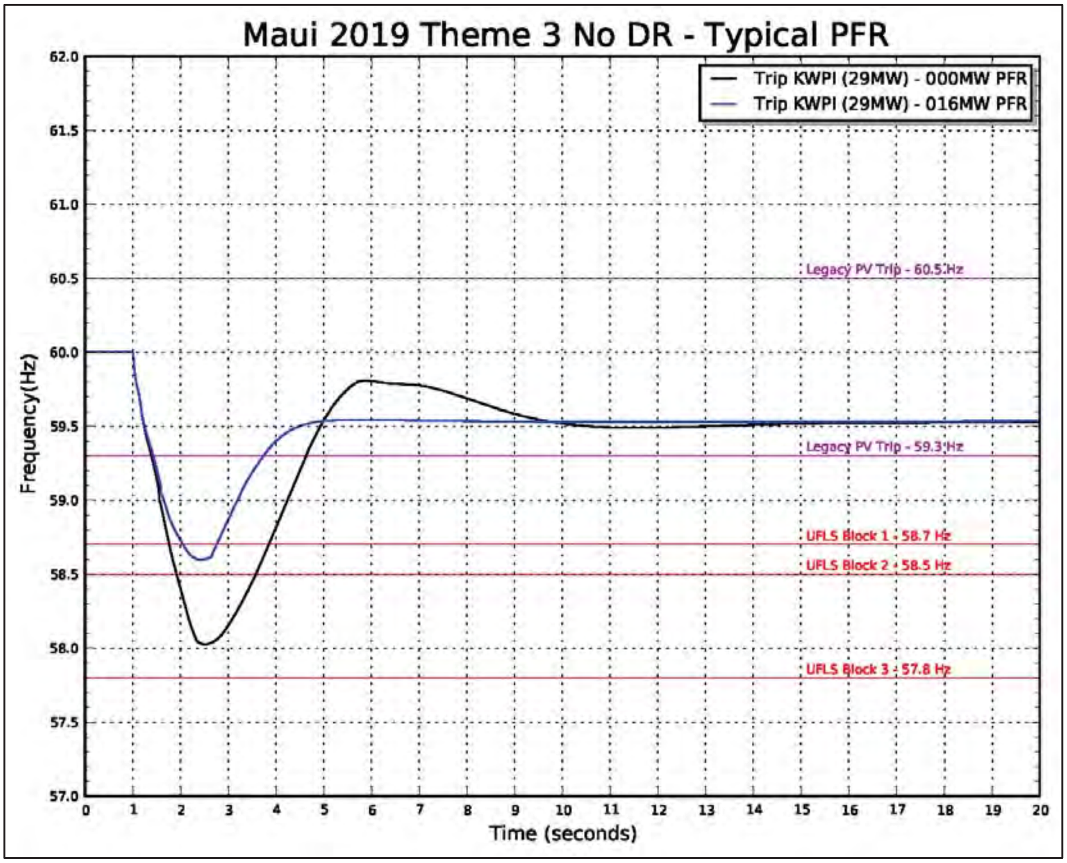

Figure O-204. Frequency Response Profile for PFR Typical Hour

Figure O-204 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 16 MW. This is in addition to the 33 MW of upward regulation from thermal generation.

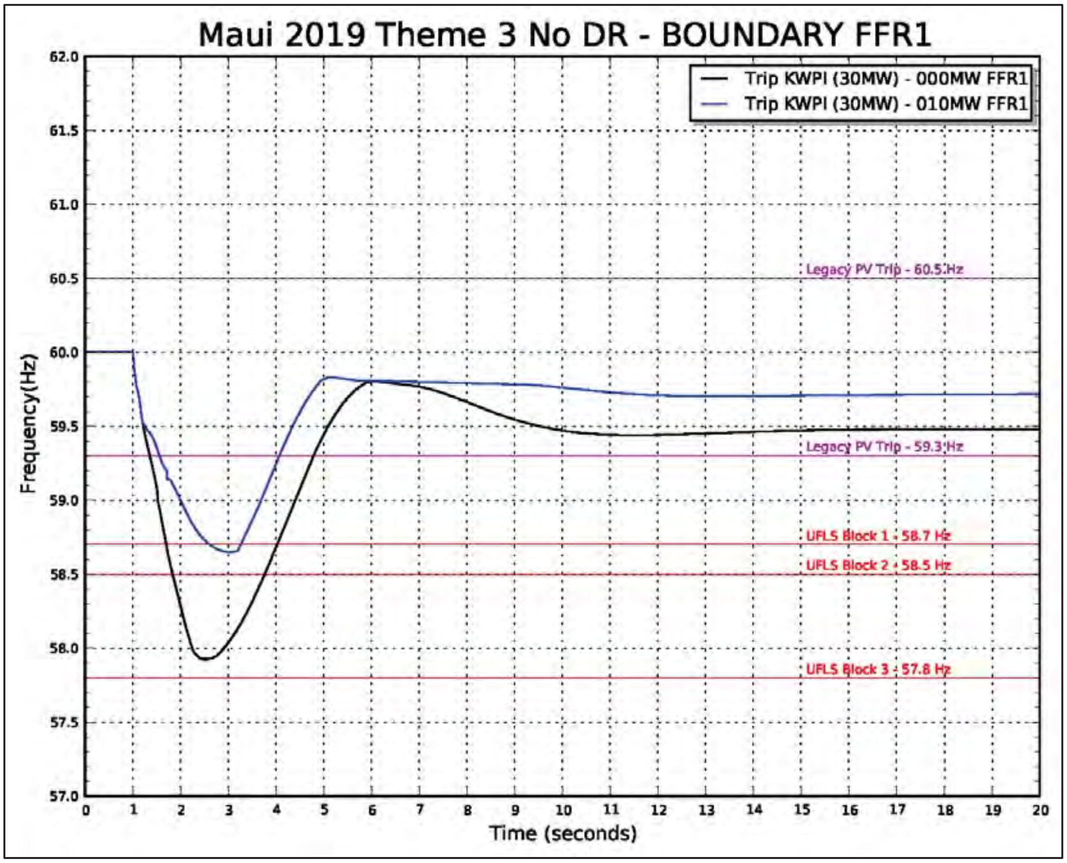

Figure O-205. Frequency Response Profile for FFR1 Boundary Hour

Figure O-205 shows the frequency response profile for a KWP I trip at 30 MW for a boundary hour. System kinetic energy is 300 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.5 MW. With no FFR, the frequency nadir is 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 10 MW.

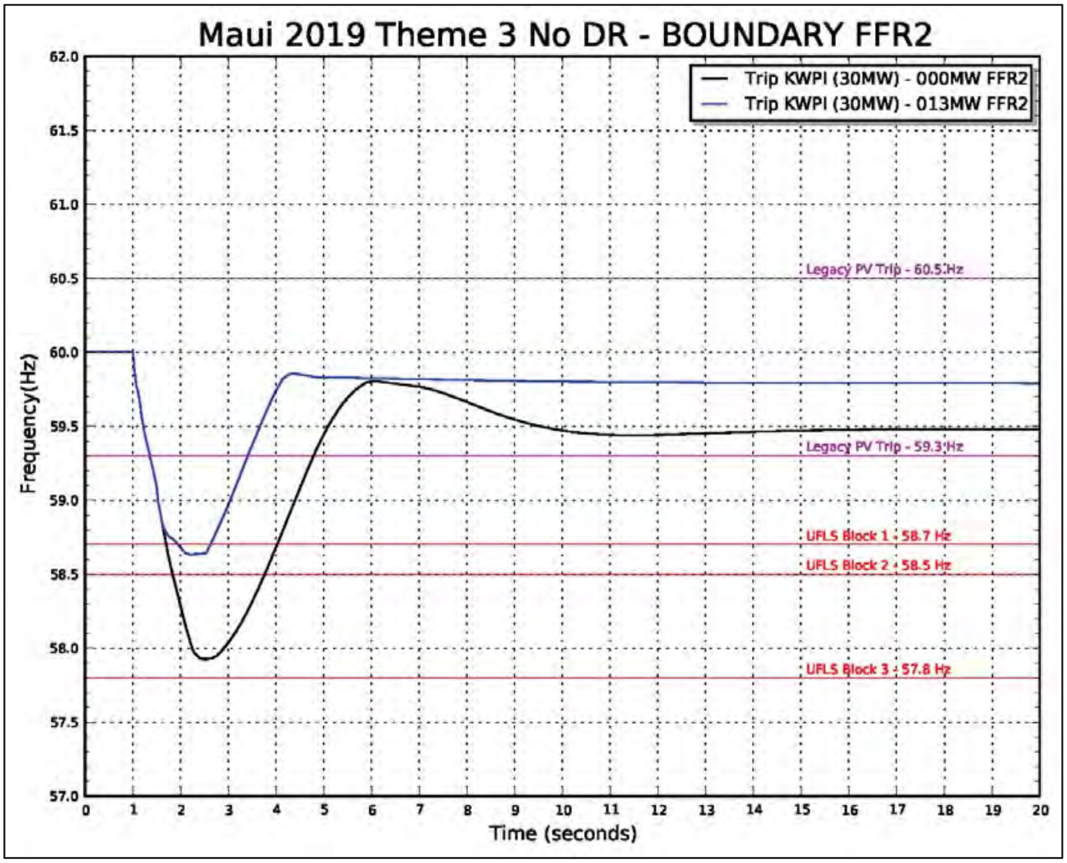

Figure O-206. Frequency Response Profile for FFR2 Boundary Hour

Figure O-206 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

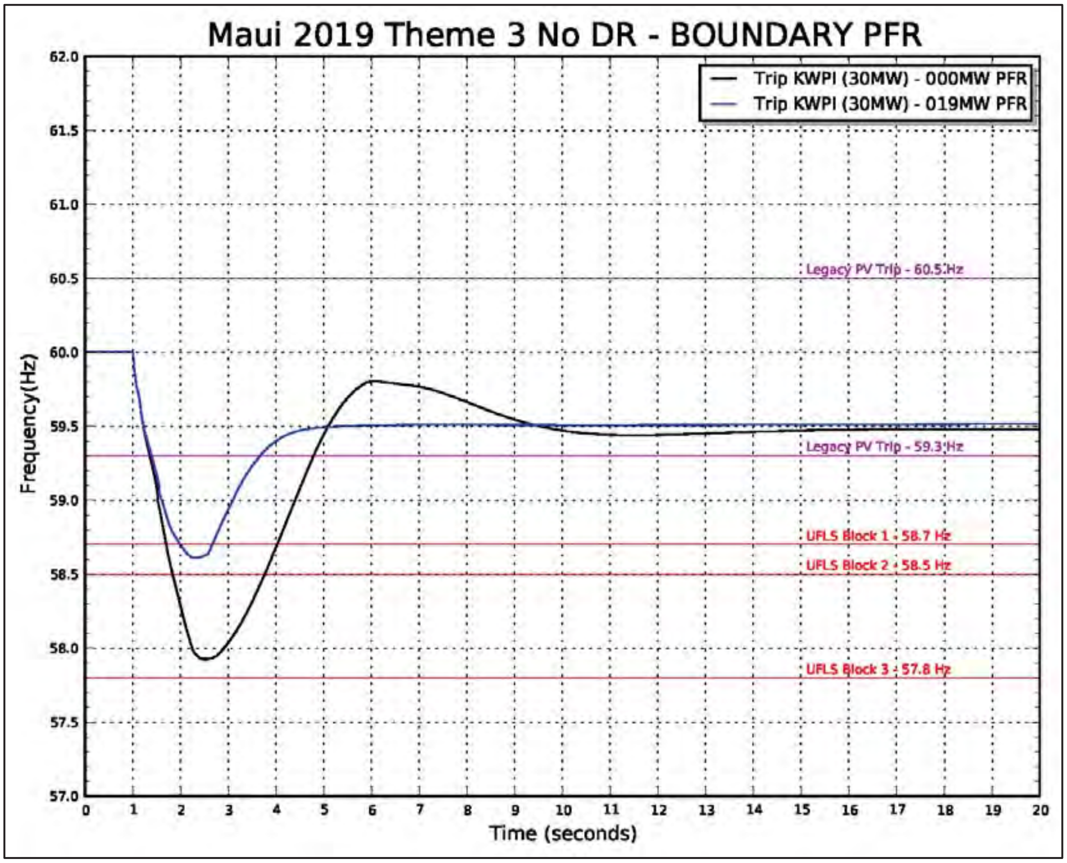

Figure O-207. Frequency Response Profile for PFR Boundary Hour

Figure O-207 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 19 MW. This is in addition to the 46 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Sun 3/27/2019 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	8.5	11.5	2.6
Maalaea 15	13.0	5.0	2.46	18.5	46	6.0	7.0	1.0
Maalaea 16	20.0	5.9	2.02	26.8	54	8.5	11.5	2.6
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51	8.0	4.3	0.1
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					105%	22	
-KWP	30	0						
-Auwahi	21	0					21	
-KWPII	21	0					1	
DG-PV	121	0				85%	103	
DER Grid Ex	4.2	0				71%	3	
Total System MVA							117	
Total Kinetic Energy							352	
Total Load							173	
Total Thermal Generation							41	
Total Renewable Generation							128	
Total Generation							169	
Excess Generation							-4	
Regulation Requirement							0	
Total Up Regulation							34	
Total Down Regulation							6	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		6.1
		60.5Hz Capacity		69.5		60.5Hz Output		59.2

Table O-83. Unit Commitment and Dispatch Fault Analysis 2019

Table O-83 shows the unit commitment and dispatch for the 69 kV fault analysis (3/27/19, 1:00 PM). Inverter-based generation is 103 MW.

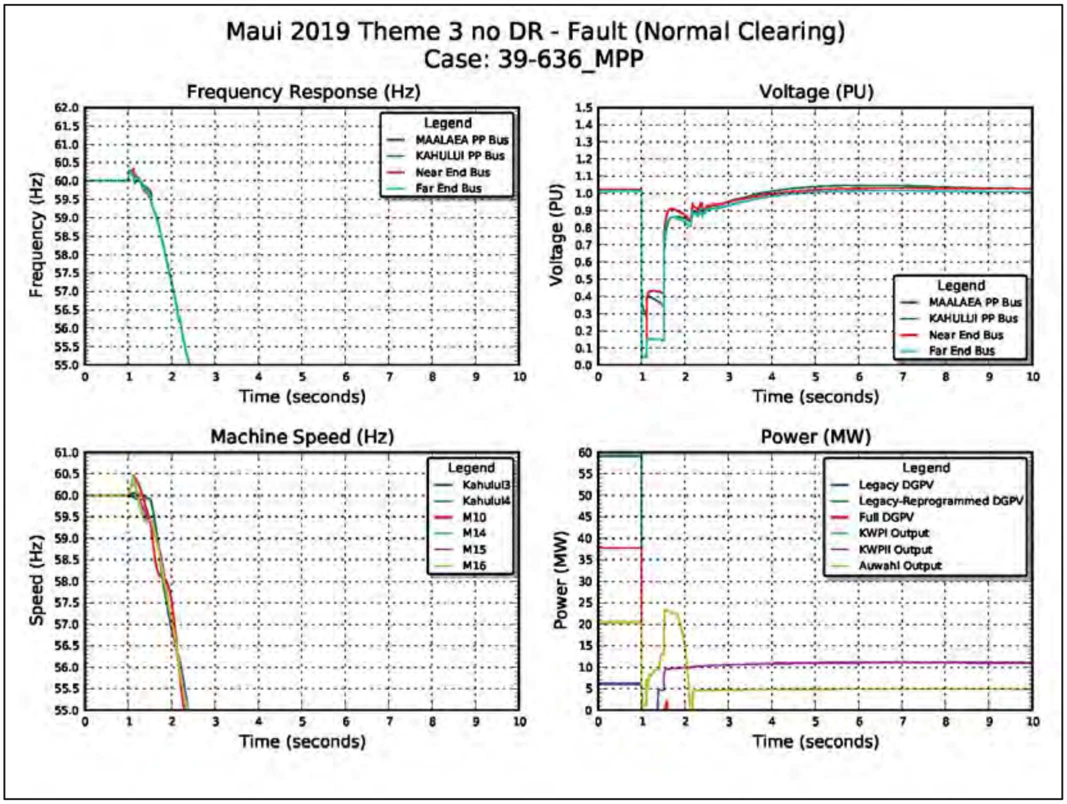

Figure O-208. System Performance for Normally Cleared Fault

Figure O-208 shows the system performance for a normally cleared fault at the Maʻalaea end of the Maʻalaea-Waiinu circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 103 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

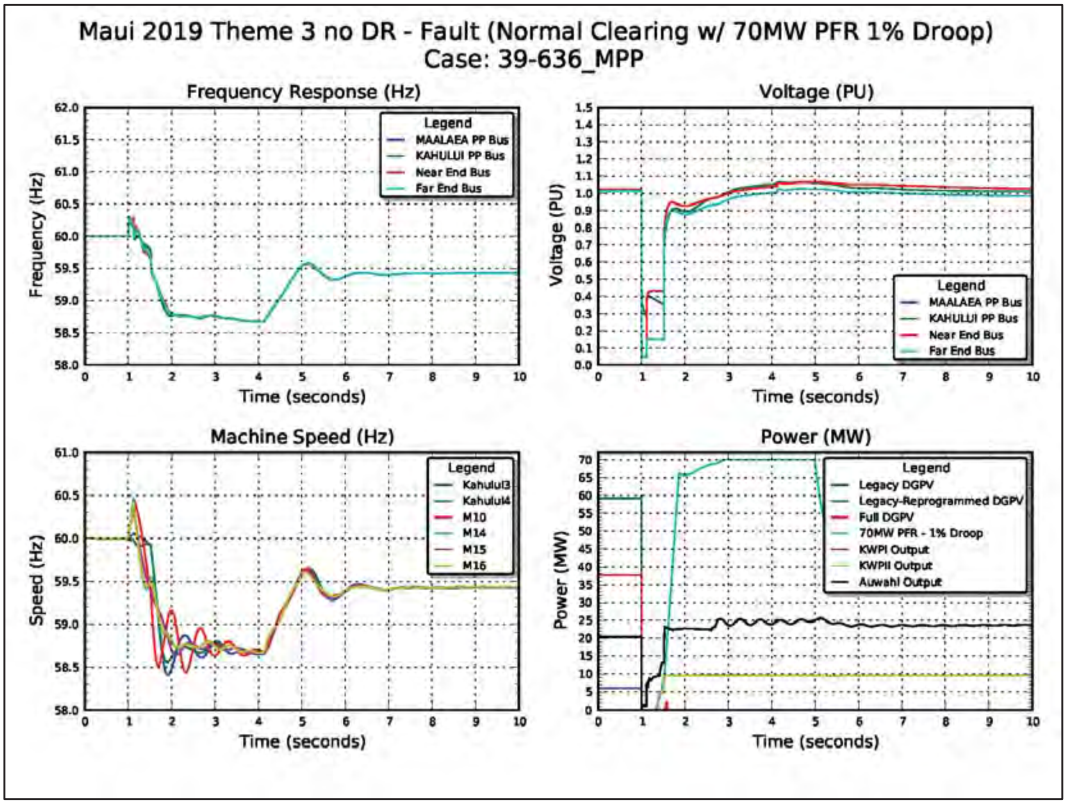

Figure O-209. Normally Cleared Fault Sensitivity 70 MW PFR

Figure O-209 shows system performance with the addition of the 70 MW PFR at 1 % droop response. For the purpose of this analysis, a 70 MW BESS located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 70 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2019 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 70MW PFR	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-84. Summary of Results Fault Analysis 2019

Table O-84 shows the results of the 69 kV fault analysis with 70 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Mon 8/17/2020 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.5	7.0	1.5
Kahului 4	11.5	3.0	3.48	15.6	54	4.5	7.0	1.5
Maalaea 14	20.0	5.9	2.02	28.8	58	7.5	12.5	1.5
Maalaea 15	13.0	4.0	2.46	18.5	46	4.9	8.1	0.9
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54	14.0	5.5	8.1
Maalaea 18	12.8	3.0	2.46	18.5	46	9.8	3.0	6.8
Maalaea 19	19.5	5.9	2.02	26.8	54	14.0	5.5	8.1
Maalaea 10	12.3	7.9	3.28	15.6	51	7.9	4.4	0.0
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Kahului 2	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Total Wind	162					126		
-KWP	30	0				28		
-Auwahi	21	0				10		
-KWPII	21	0				20		
-New Wind 1	30	0				23		
-New Wind 2	30	0				23		
-New Wind 3	30	0				23		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	125	0						
DER Grid Ex	4	0						
Total System MVA							204	
Total Kinetic Energy							538	
Total Load							206	
Total Thermal Generation							79	
Total Renewable Generation							126	
Total Generation							205	
Excess Generation							-1	
Regulation Requirement							0	
Total Up Regulation							52	
Total Down Regulation							27	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0

Table O-85. Unit Commitment and Dispatch 2020 QV Analysis

Table O-85 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Mon 8/17/2020 Hour 20		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	3.8	0.3	3.8
Maalaea 15	2.9	0.0	0.4	2.5	0.4
Maalaea 16	4.1	0.0	2.0	2.1	2.0
Maalaea 17	15.0	0.0	4.0	11.0	4.0
Maalaea 18	12.0	0.0	2.0	10.0	2.0
Maalaea 19	15.0	0.0	4.0	11.0	4.0
Maalaea 10	9.4	0.0	0.0	9.3	0.0
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0	0.0	3.0	0.0
Kahului 2	3.0	0.0	0.0	3.0	0.0
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	0.0	14.5	0.2
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.4	9.4	0.4
-New Wind 2	9.9	0.0	0.4	9.4	0.4
-New Wind 3	9.9	0.0	0.4	9.4	0.4
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			16.3		
Total Renewable MVAR Generation			1.3		
Total Cap Bank MVAR			54.0		
Charging MVAR			6.1		
Total MVAR Supply			77.6		
Total MVAR Load			32.4		
Total MVAR Losses			45.1		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				128	
Total MVAR Absorb Capability					16.3

Table O-86. MVAR Capability 2020 QV Analysis

Table O-86 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	MPP-Kihei 69 kV
104	MPP-Waiinu 69 kV
113	Wailea-Auwahi Tap 69 kV

Table O-87. N-1 Contingencies 2020 QV Analysis

Table O-87 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

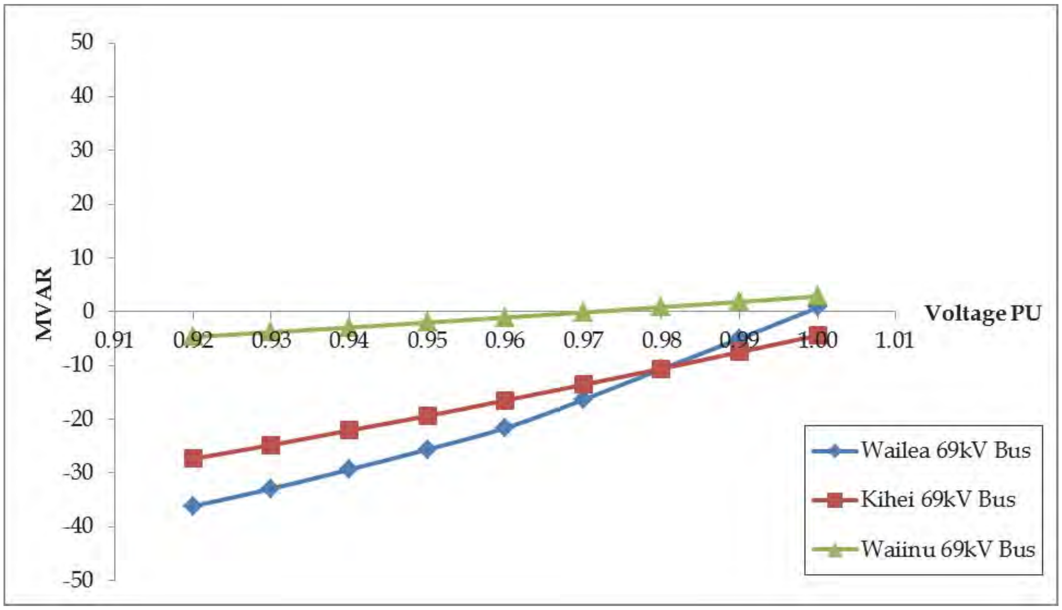

Figure O-210. QV Curves 2020

Figure O-210 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	1	113	-5	113	-11	113	-16	113	-22	102	-26	102	-29	102	-33	102	-36
35	Kihei 69 kV Bus	102	-4	102	-7	102	-11	102	-14	102	-16	102	-19	102	-22	102	-25	102	-27
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-5

Table O-88. Summary of Results 2020 QV Analysis

Table O-88 shows the results of the QV analysis for 2020. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

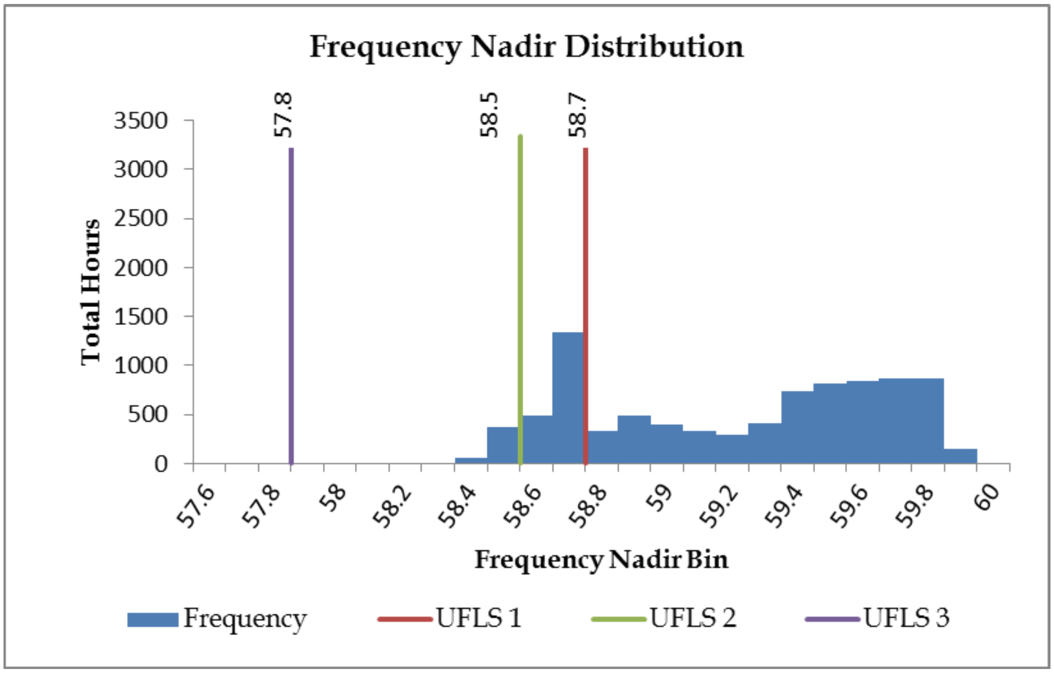

Figure O-211. Frequency Nadir Histogram for 2020

Figure O-211 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 374 hours was 12:00 PM on Monday, May 11. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 53 hours was 4:00 AM on Wednesday, November 25. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

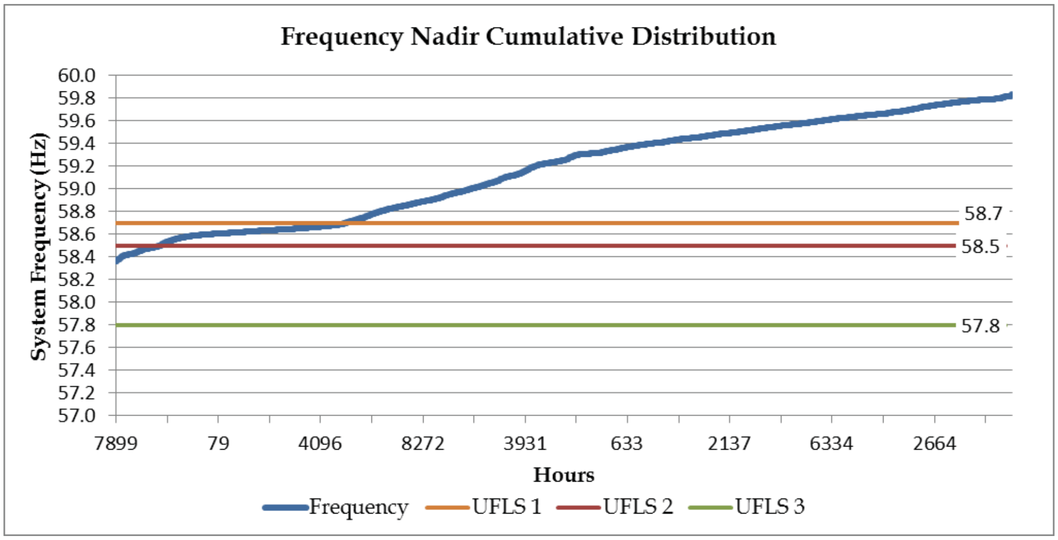

Figure O-212. Frequency Nadir Duration Curve 2020

Figure O-212 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 403 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 05/11/2020 Hour 12			Theme 3 - KWP I Trip Boundary Wed 11/25/2020 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0			
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	16.0	4.0	10.1	8.0	12.0	2.1
Maalaea 15	13.0	3.0	2.46	18.5	46				4.0	9.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54				8.0	12.0	2.1
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	162					48			75		
-KWP	30	0				27			24		
-Auwahi	21	0									
-KWPII	21	0				21			20		
-New Wind 1	30	0							30		
-New Wind 2	30	0							1		
-New Wind 3	30	0									
Total Utility PV	80					2					
-Utility PV1	20	0				2					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	125	0				99					
DER Grid Ex	4	0				5					
Total System MVA							58			90	
Total Kinetic Energy							305			316	
Total Load							180			99	
Total Thermal Generation							26			25	
Total Renewable Generation							154			75	
Total Generation							180			100	
Excess Generation							0			1	
Regulation Requirement							0			0	
Total Up Regulation							17			40	
Total Down Regulation							10			4	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		5.7	59.3Hz Output		0.0
		60.5Hz Capacity		69.5		60.5Hz Output		55.0	60.5Hz Output		0.0

Table O-89. Unit Commitment and Dispatch 2020

Table O-89 shows the unit commitment and dispatch for the typical hour (5/11/20, 12:00 PM) and boundary hour (11/25/20, 4:00 AM).

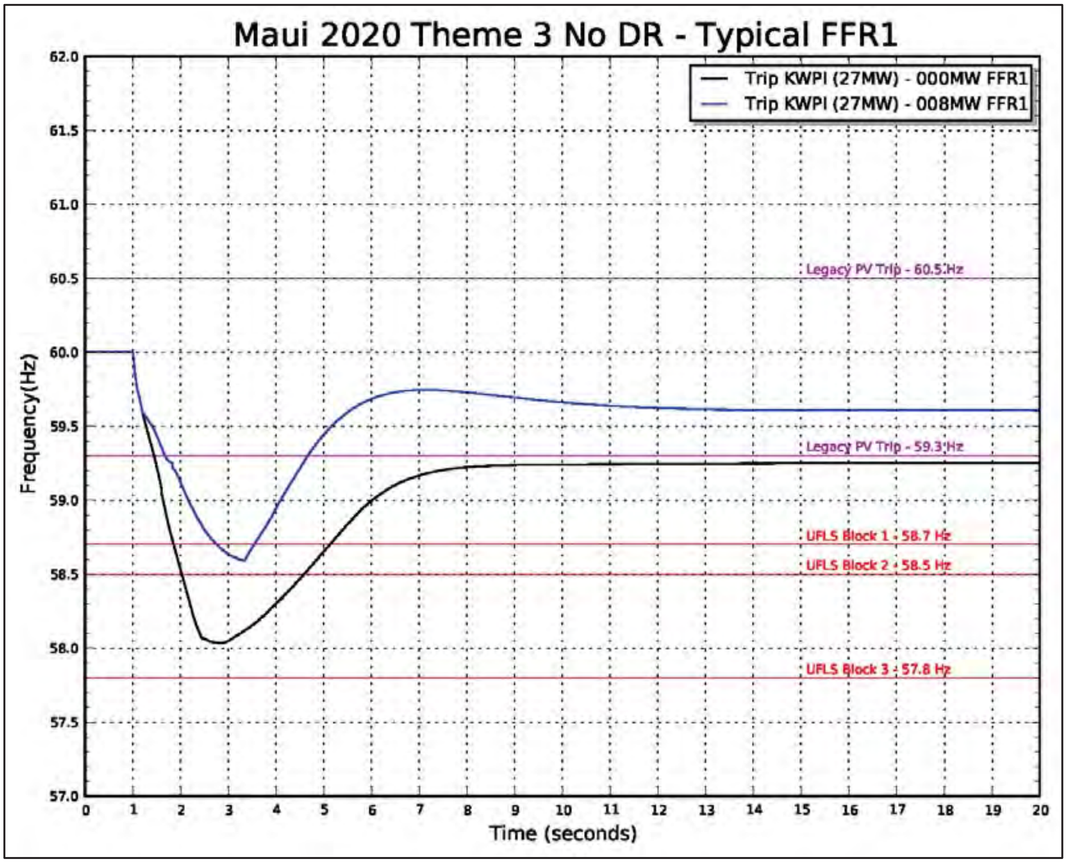

Figure O-213. Frequency Response Profile for FFR1 Typical Hour

Figure O-213 shows the frequency response profile for a KWP 1 trip at 27 MW for a typical hour. System kinetic energy is 305 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.7 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

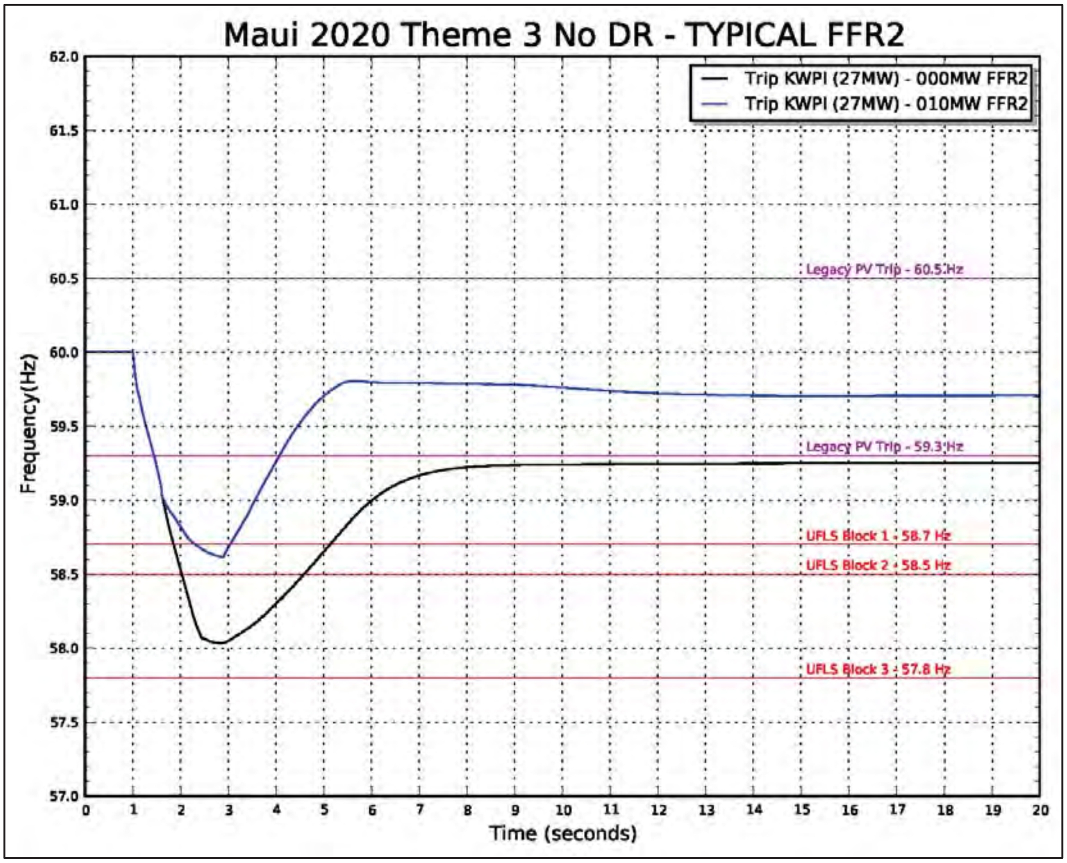

Figure O-214. Frequency Response Profile for FFR2 Typical Hour

Figure O-214 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 10 MW.

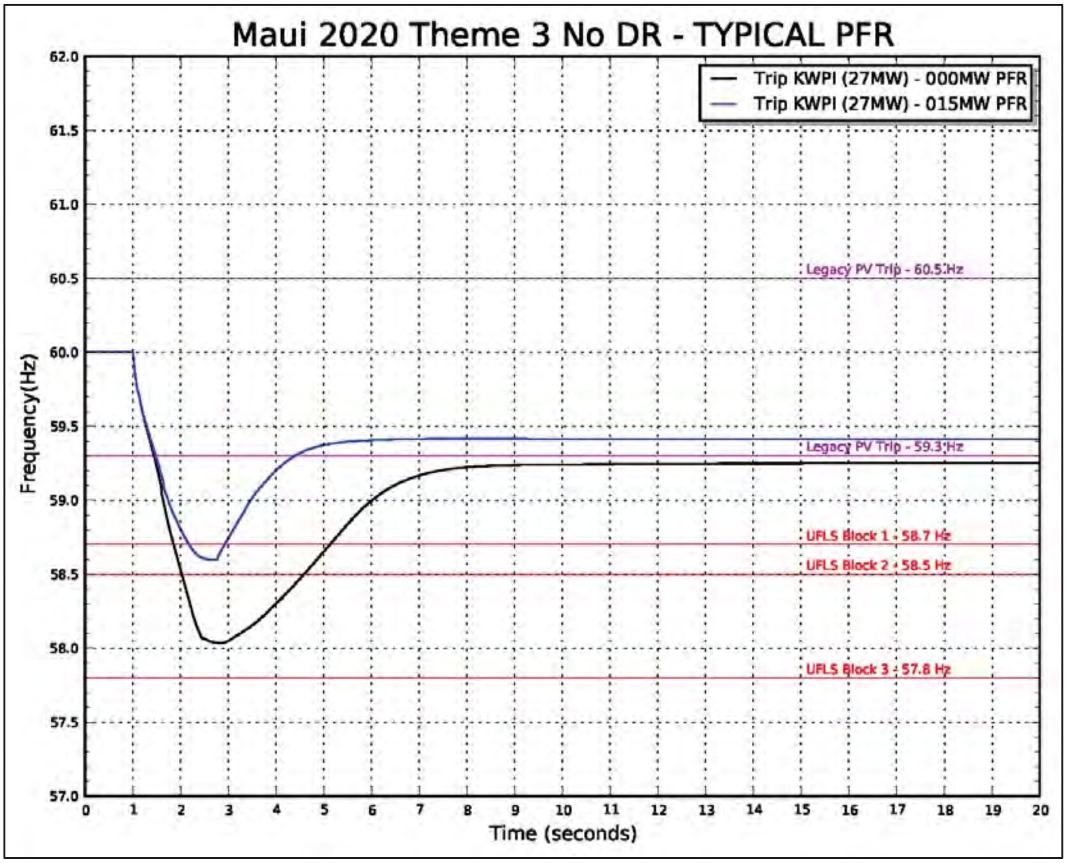

Figure O-215. Frequency Response Profile for PFR Typical Hour

Figure O-215 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 17 MW of upward regulation from thermal generation.

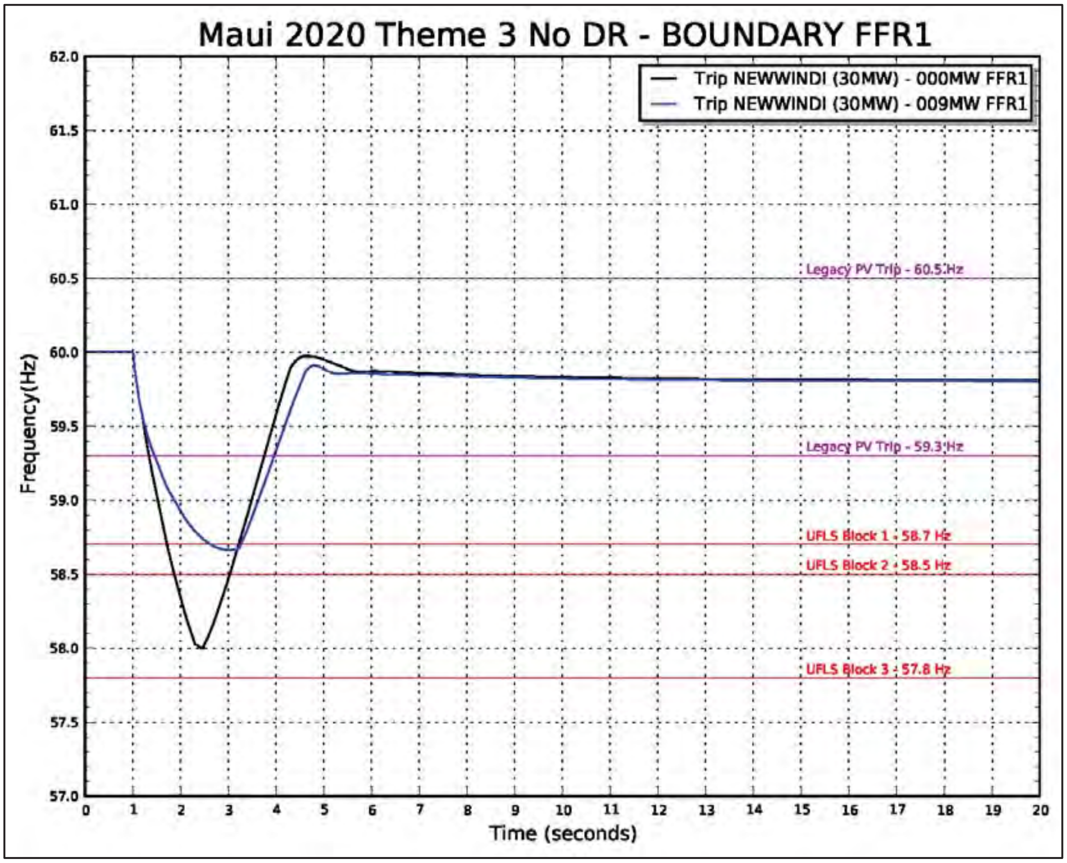

Figure O-216. Frequency Response Profile for FFR1 Boundary Hour

Figure O-216 shows the frequency response profile for a Windfarm trip at 30 MW for a boundary hour. System kinetic energy is 316 MW-sec. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

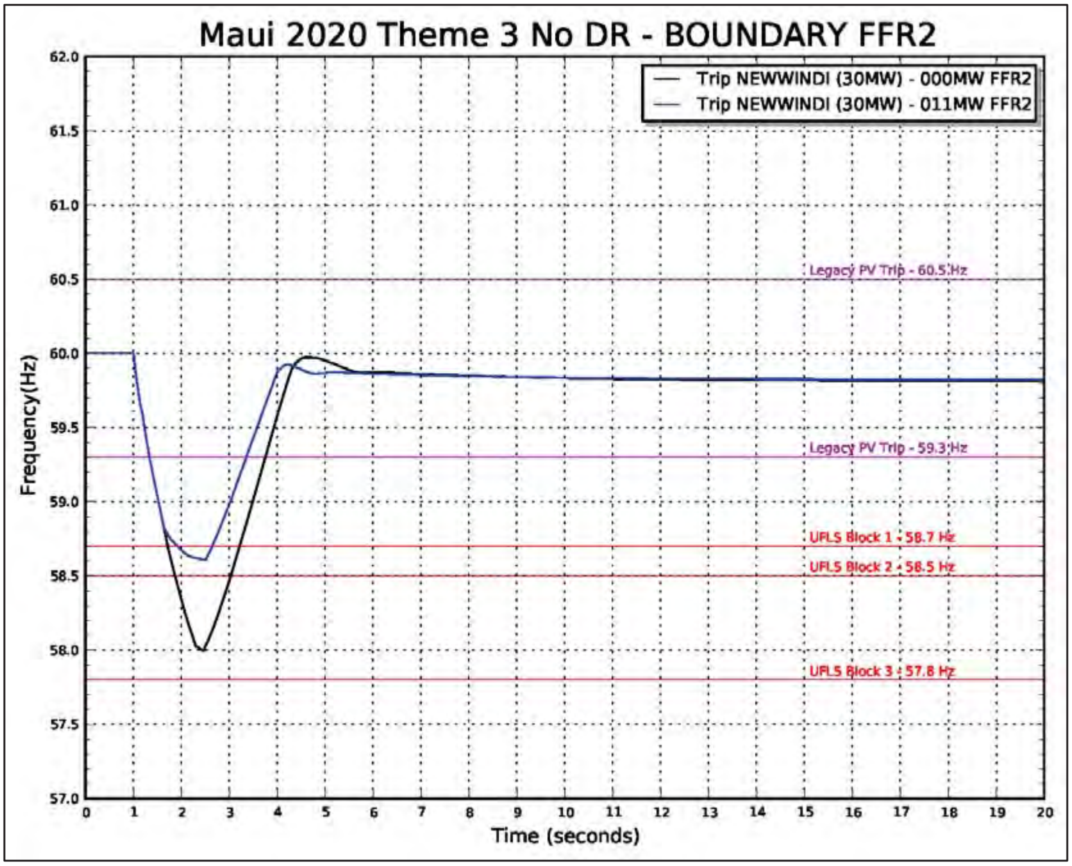

Figure O-217. Frequency Response Profile for FFR2 Boundary Hour

Figure O-217 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

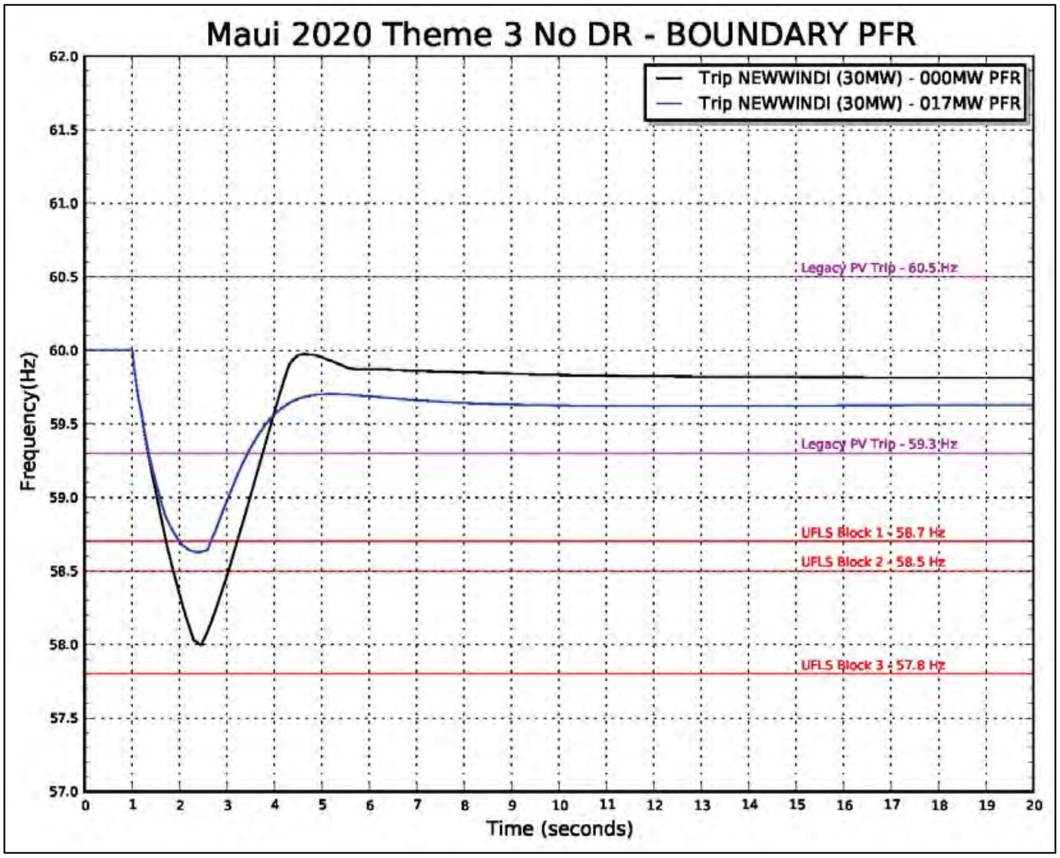

Figure O-218. Frequency Response Profile for PFR Boundary Hour

Figure O-218 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 17 MW. This is in addition to the 40 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Sat 5/9/2020 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	15.7	4.3	9.8
Maalaea 15	13.0	3.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54	12.3	7.2	6.4
Maalaea 18	12.8	3.0	2.46	18.5	46	4.3	8.5	1.3
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Total Wind	162					13		
-KWP	30	0						
-Auwahi	21	0				13		
-KWPII	21	0						
-New Wind 1	30	0						
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					3		
-Utility PV1	20	0				3		
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	125	0				103		
DER Grid Ex	4	0				4		
Total System MVA							72	
Total Kinetic Energy							262	
Total Load							164	
Total Thermal Generation							42	
Total Renewable Generation							123	
Total Generation							165	
Excess Generation							1	
Regulation Requirement							0	
Total Up Regulation							20	
Total Down Regulation							17	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.9
	60.5Hz Capacity			69.5		60.5Hz Output		57.3

Table O-90. Unit Commitment and Dispatch Fault Analysis 2020

Table O-90 shows the unit commitment and dispatch for the 69 kV fault analysis. Inverter-based generation is 103 MW.

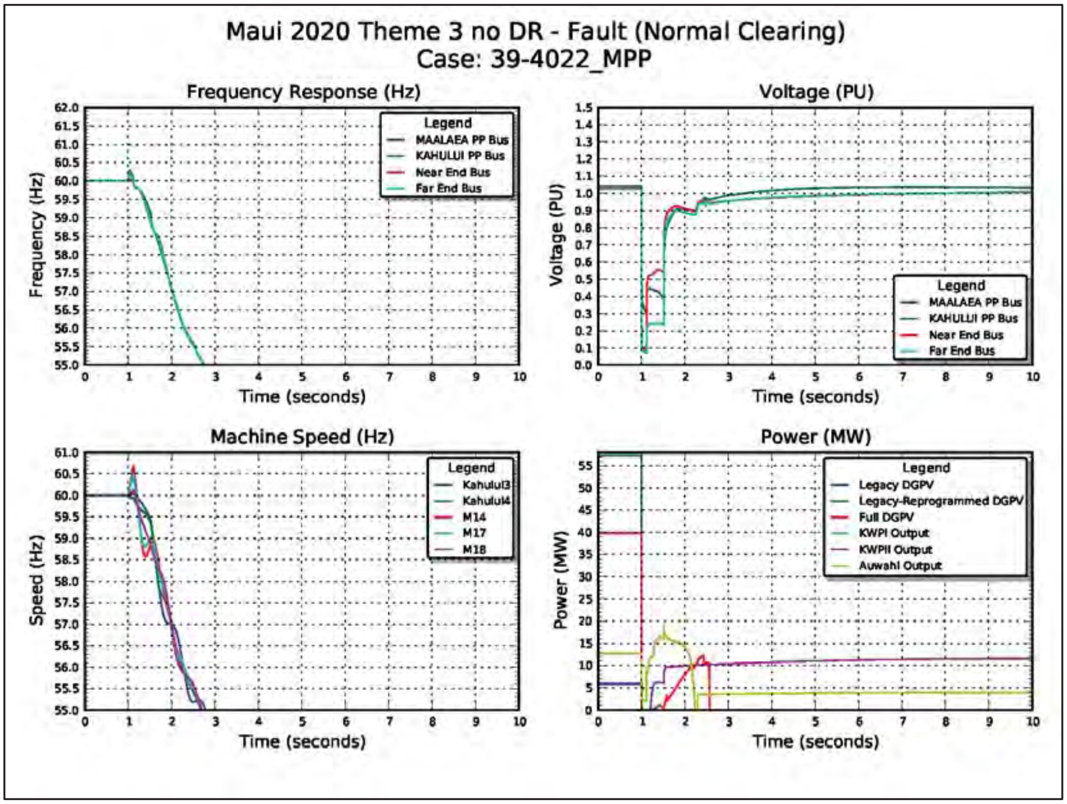

Figure O-219. System Performance Normally Cleared Fault

Figure O-219 shows the system performance for a normally cleared fault at the Ma‘alaea end of the Ma‘alaea-Pu‘unene circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 103 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

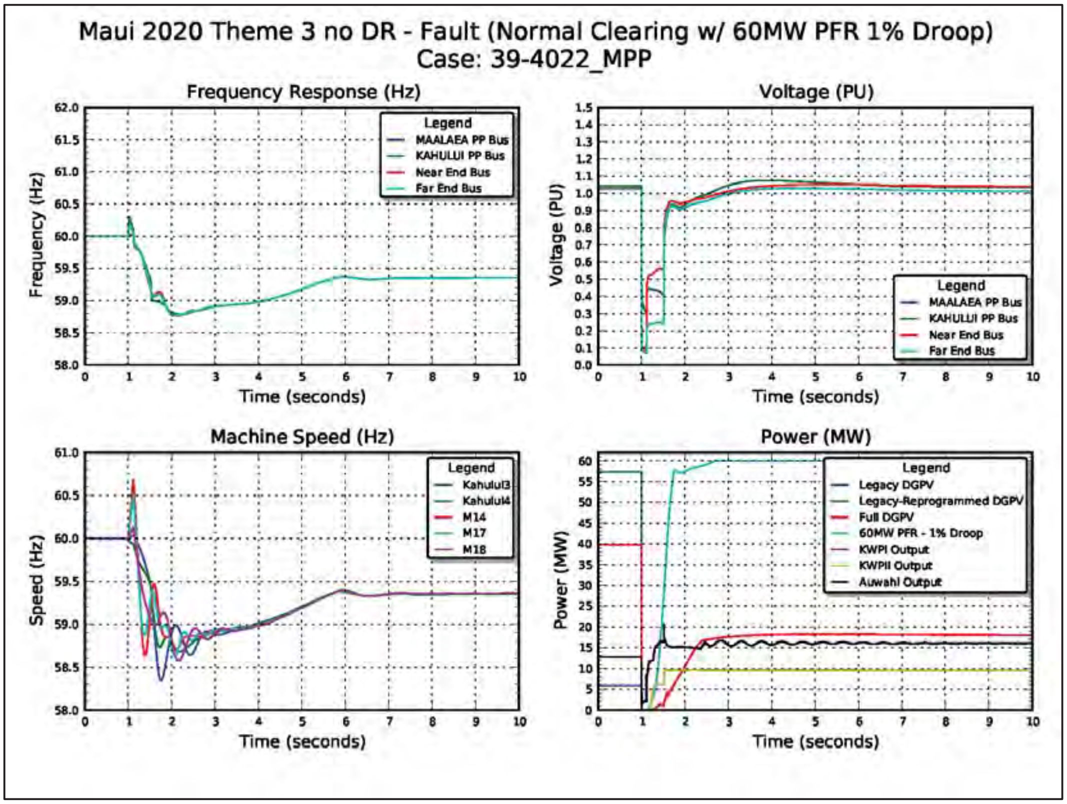

Figure O-220. Normally Cleared Fault Sensitivity 60 MW PFR

Figure O-220 shows system performance with the addition of the 60 MW of PFR at 1% droop response. For the purpose of this analysis, a 60 MW BESS was located at Maʻalaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 60 MW BESS. The aggregate response from synchronous units, the BESS resources, restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2020 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 60 MW PFR	Mitigation: 5-Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-91. Summary of Results Fault Analysis 2020

Table O-91 shows the results of the 69 kV fault analysis with 60 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Fri 10/29/2021 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.5	7.0	1.5
Kahului 4	11.5	3.0	3.48	15.6	54	4.5	7.0	1.5
Maalaea 14	20.0	5.9	2.02	28.8	58	7.5	12.5	1.6
Maalaea 15	13.0	4.0	2.46	18.5	46	4.9	8.1	0.9
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54	13.8	5.7	7.9
Maalaea 18	12.8	3.0	2.46	18.5	46	4.8	8.0	1.8
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.0	3.28	15.6	51	7.1	5.2	0.1
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	162					148		
-KWP	30	0				30		
-Auwahi	21	0				21		
-KWPII	21	0				21		
-New Wind 1	30	0				25		
-New Wind 2	30	0				25		
-New Wind 3	30	0				25		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	128	0						
DER Grid Ex	8	0						
Total System MVA						170		
Total Kinetic Energy						468		
Total Load						188		
Total Thermal Generation						57		
Total Renewable Generation						148		
Total Generation						205		
Excess Generation						17		
Regulation Requirement						0		
Total Up Regulation						52		
Total Down Regulation						14		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0

Table O-92. Unit Commitment and Dispatch 2021 QV Analysis

Table O-92 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Fri 10/29/2021 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	3.8	0.3	3.8
Maalaea 15	2.9	0.0	0.8	2.1	0.8
Maalaea 16	4.1	0.0	3.8	0.3	3.8
Maalaea 17	15.0	0.0	7.6	7.4	7.6
Maalaea 18	12.0	0.0	3.8	8.2	3.8
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0	0.1	9.3	0.1
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	0.0	14.5	0.2
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.8	9.0	0.8
-New Wind 2	9.9	0.0	0.8	9.0	0.8
-New Wind 3	9.9	0.0	0.8	9.0	0.8
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			19.9		
Total Renewable MVAR Generation			2.5		
Total Cap Bank MVAR			53.9		
Charging MVAR			6.1		
Total MVAR Supply			82.4		
Total MVAR Load			32.3		
Total MVAR Losses			50.0		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				102	
Total MVAR Absorb Capability					19.9

Table O-93. MVAR Capability 2021 QV Analysis

Table O-93 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	MPP-Kihei 69 kV
104	MPP-Waiinu 69 kV
113	Wailea-Auwahi Tap 69 kV

Table O-94. N-1 Contingencies 2021 QV Analysis

Table O-94 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

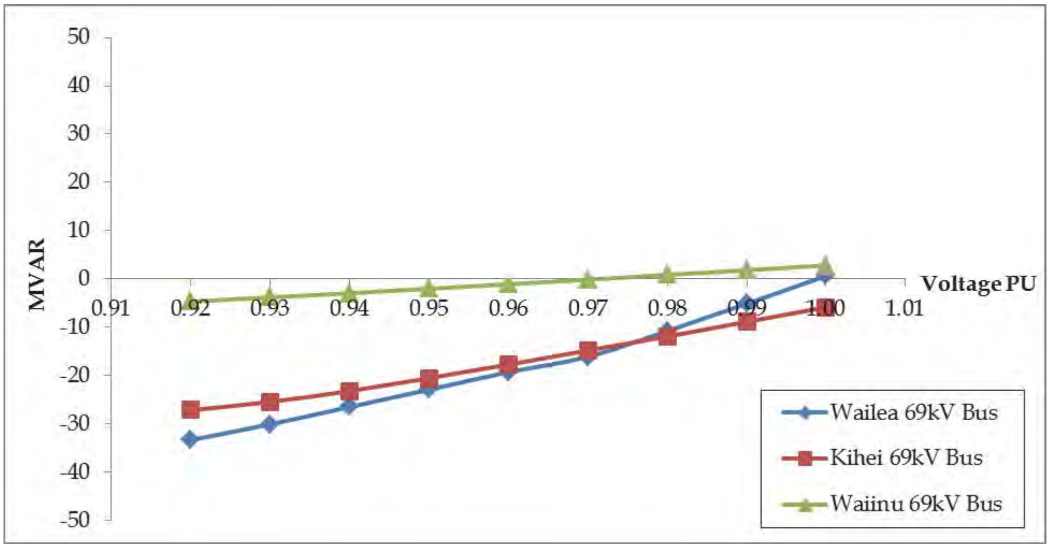

Figure O-221. QV Curves 2021

Figure O-221 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	1	113	-5	113	-11	113	-16	113	-19	113	-23	113	-27	113	-30	113	-33
35	Kihei 69 kV Bus	102	-6	102	-9	102	-12	102	-15	102	-18	102	-21	102	-23	102	-25	102	-27
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-5

Table O-95. Summary of Results 2021 QV Analysis

Table O-95 shows the results of the QV analysis for 2021. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

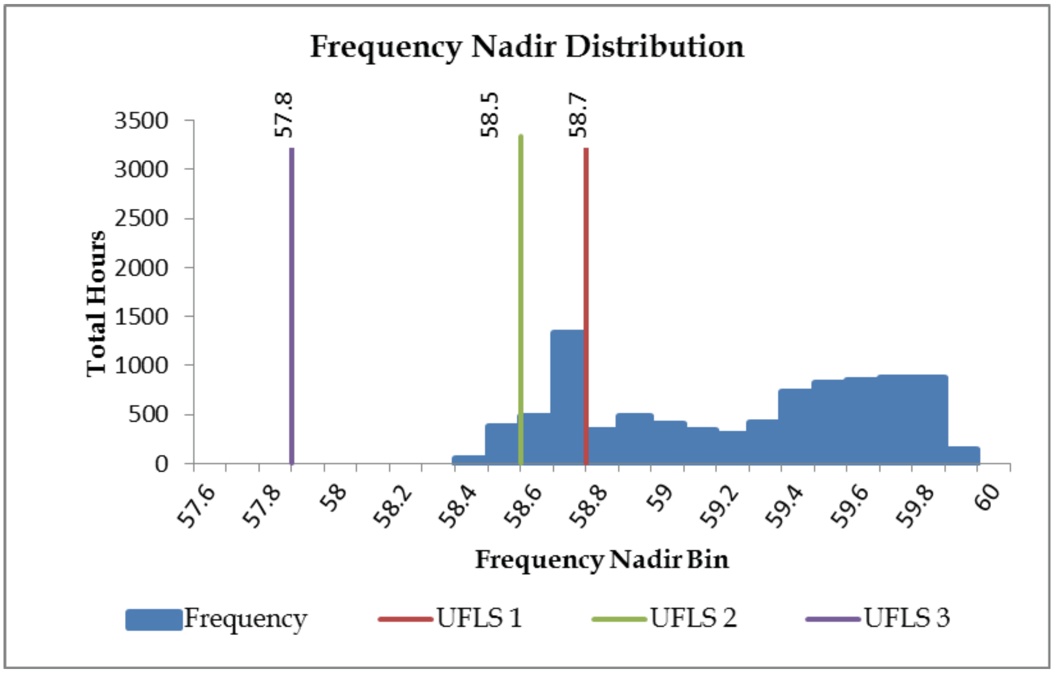

Figure O-222. Frequency Nadir Histogram for 2021

Figure O-222 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 374 hours was 12:00 PM on Monday, May 10. The frequency nadir range for the typical hour is 58.5 - 58.6 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 53 hours was 4:00 PM on Saturday, March 13. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

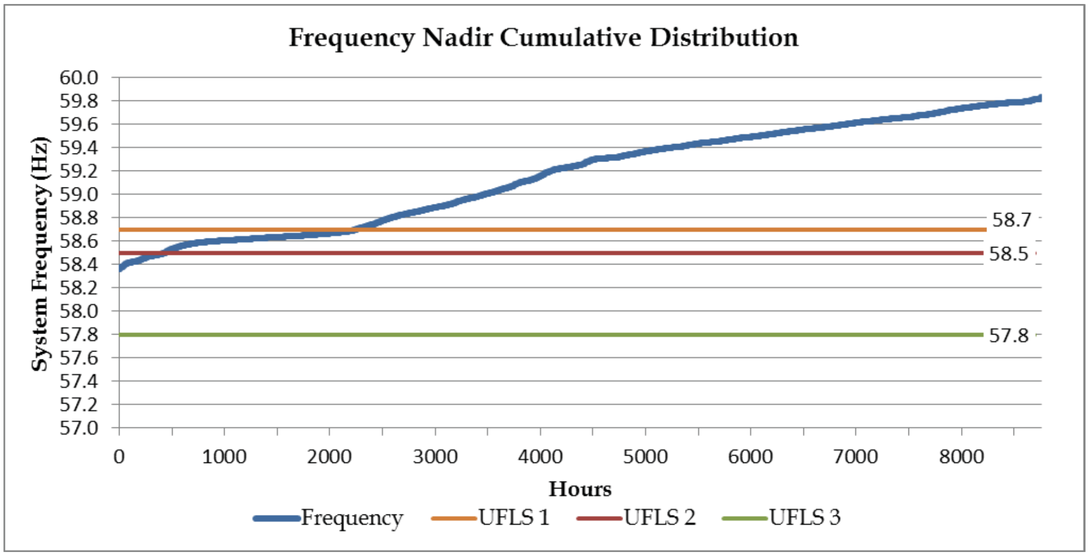

Figure O-223. Frequency Nadir Duration Curve 2021

Figure O-223 shows the frequency nadir duration curve for the Theme 3 resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 427 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 05/10/2021 Hour 12			Theme 3 - KWP I Trip Boundary Sat 3/13/2021 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0			
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	12.0	8.0	6.1	14.0	6.0	8.1
Maalaea 15	13.0	4.0	2.46	18.5	46	4.0	9.0	0.0	4.0	9.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					48			60		
-KWP	30	0				27			30		
-Auwahi	21	0									
-KWPII	21	0				21					
-New Wind 1	30	0							30		
-New Wind 2	30	0									
-New Wind 3	30	0									
Total Utility PV	80					2			0		
-Utility PV1	20	0				2					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	128	0				103			79		
DER Grid Ex	8	0				6			4		
Total System MVA						74			61		
Total Kinetic Energy						351			262		
Total Load						184			170		
Total Thermal Generation						26			23		
Total Renewable Generation						159			143		
Total Generation						185			166		
Excess Generation						1			-4		
Regulation Requirement						0			0		
Total Up Regulation						30			22		
Total Down Regulation						6			8		
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		5.8	59.3Hz Output		4.4
		60.5Hz Capacity		69.5		60.5Hz Output		55.8	60.5Hz Output		42.8

Table O-96. Unit Commitment and Dispatch 2021

Table O-96 shows the unit commitment and dispatch for the typical hour (5/10/21, 12:00 PM) and boundary hour (3/13/21, 4:00 PM).

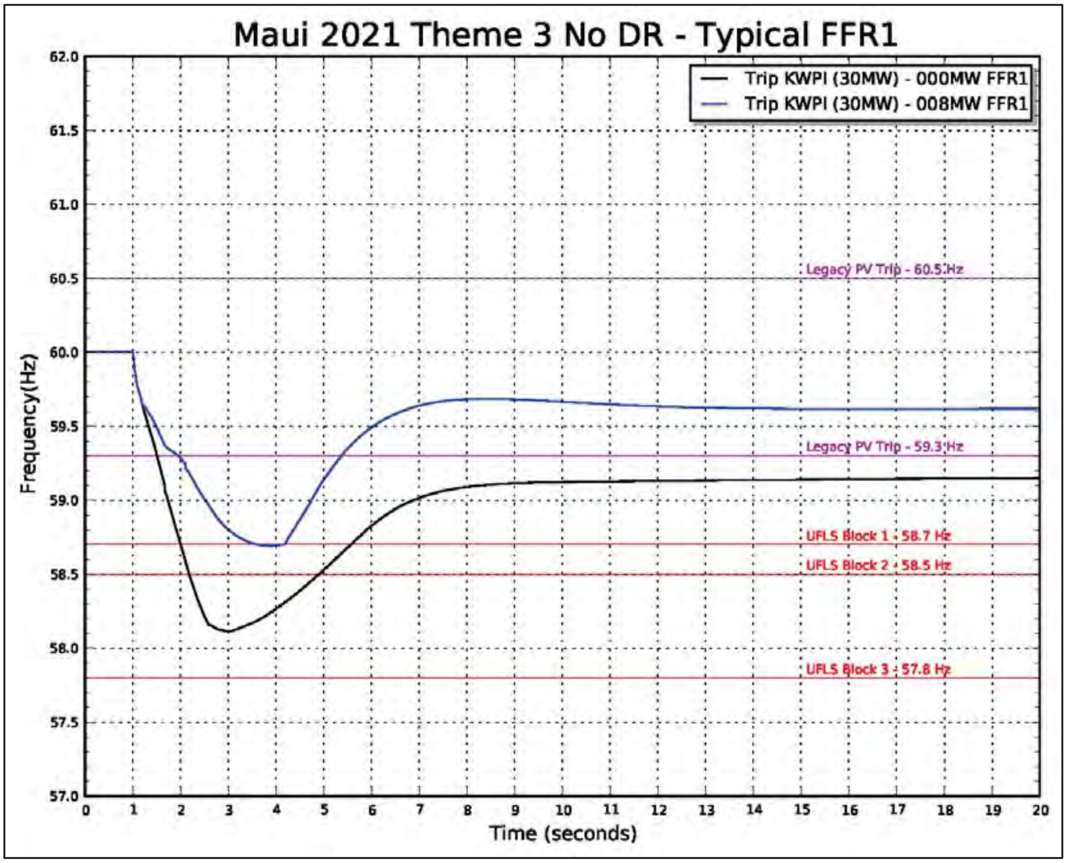

Figure O-224. Frequency Response Profile for FFR1 Typical Hour

Figure O-224 shows the frequency response profile for a KWP 1 trip at 30 MW for a typical hour. System kinetic energy is 351 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.8 MW. With no FFR, the frequency nadir is 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

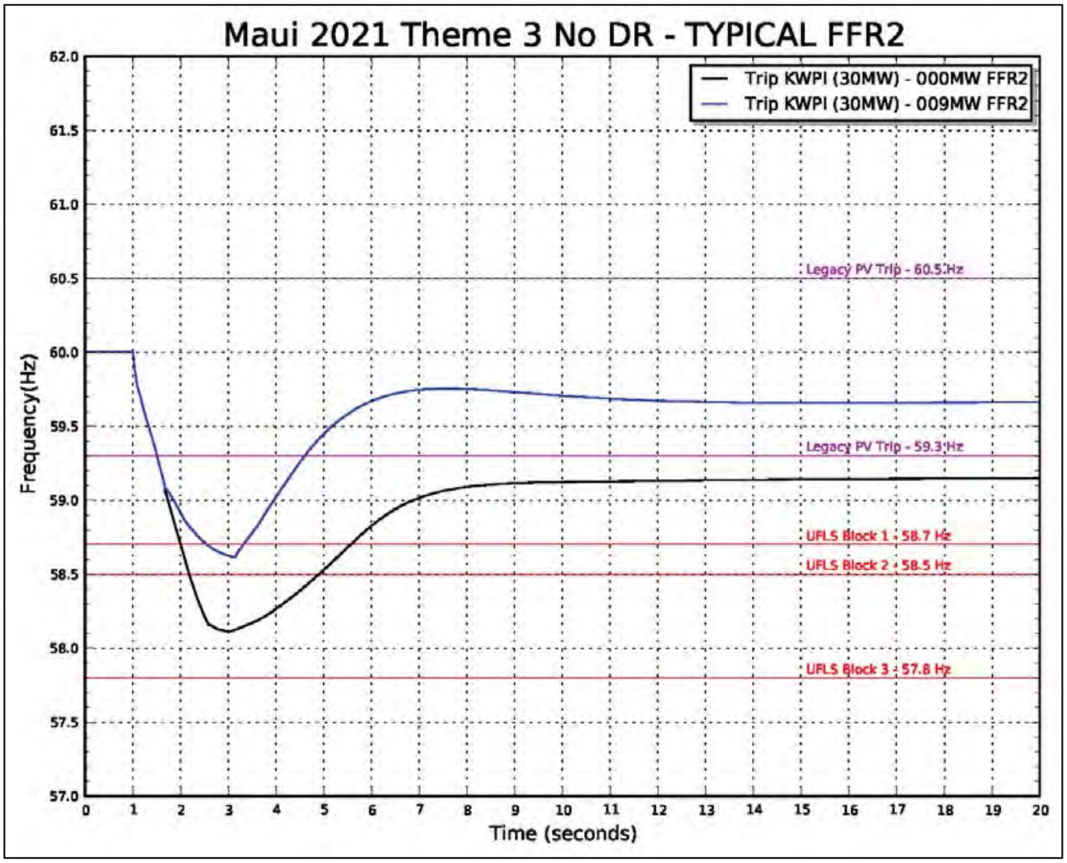

Figure O-225. Frequency Response Profile for FFR2 Typical Hour

Figure O-225 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW.

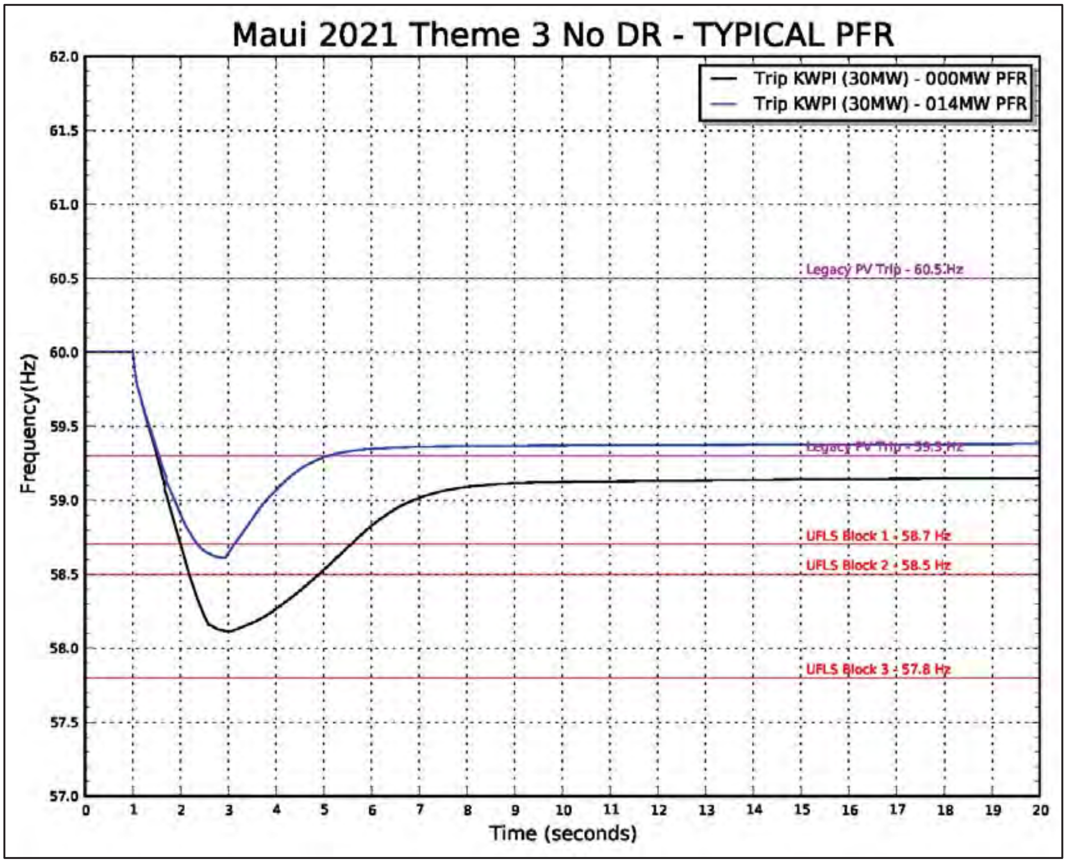

Figure O-226. Frequency Response Profile for PFR Typical Hour

Figure O-226 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

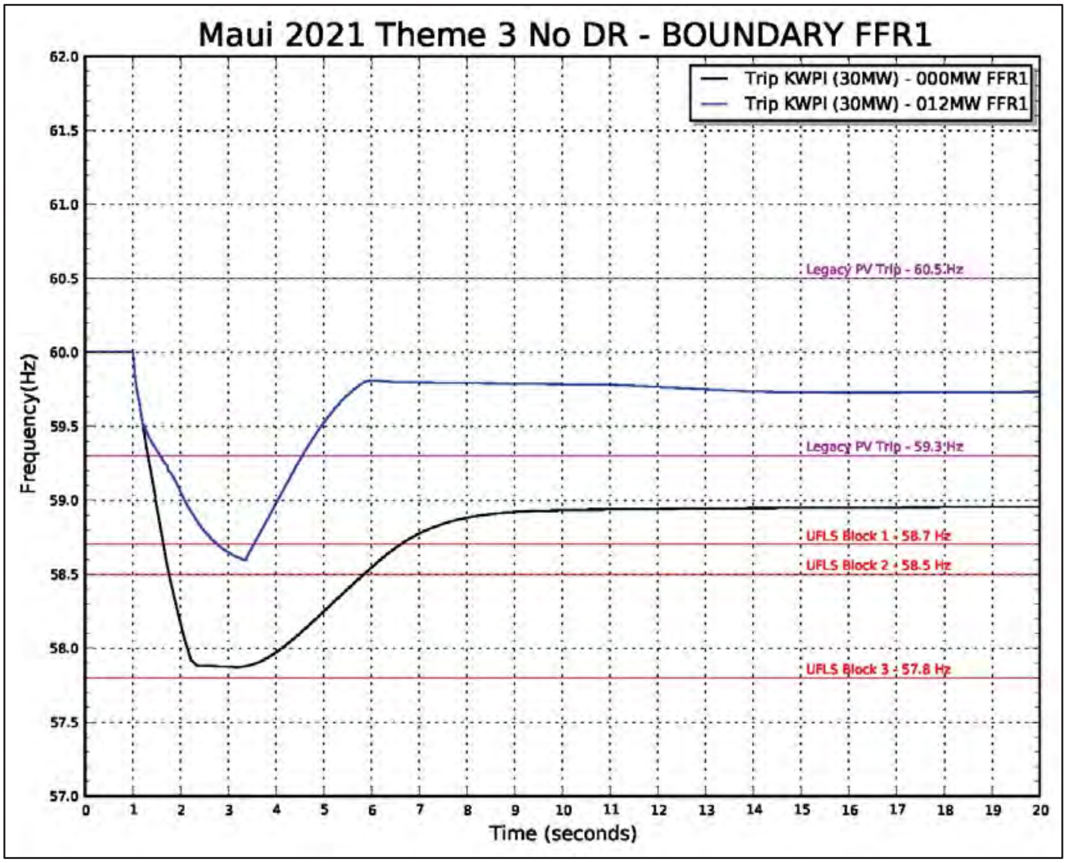

Figure O-227. Frequency Response Profile for FFR1 Boundary Hour

Figure O-227 shows the frequency response profile for a KWP 1 trip at 30 MW for a boundary hour. System kinetic energy is 262 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.4 MW. With no FFR, the frequency nadir breaches 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 12 MW.

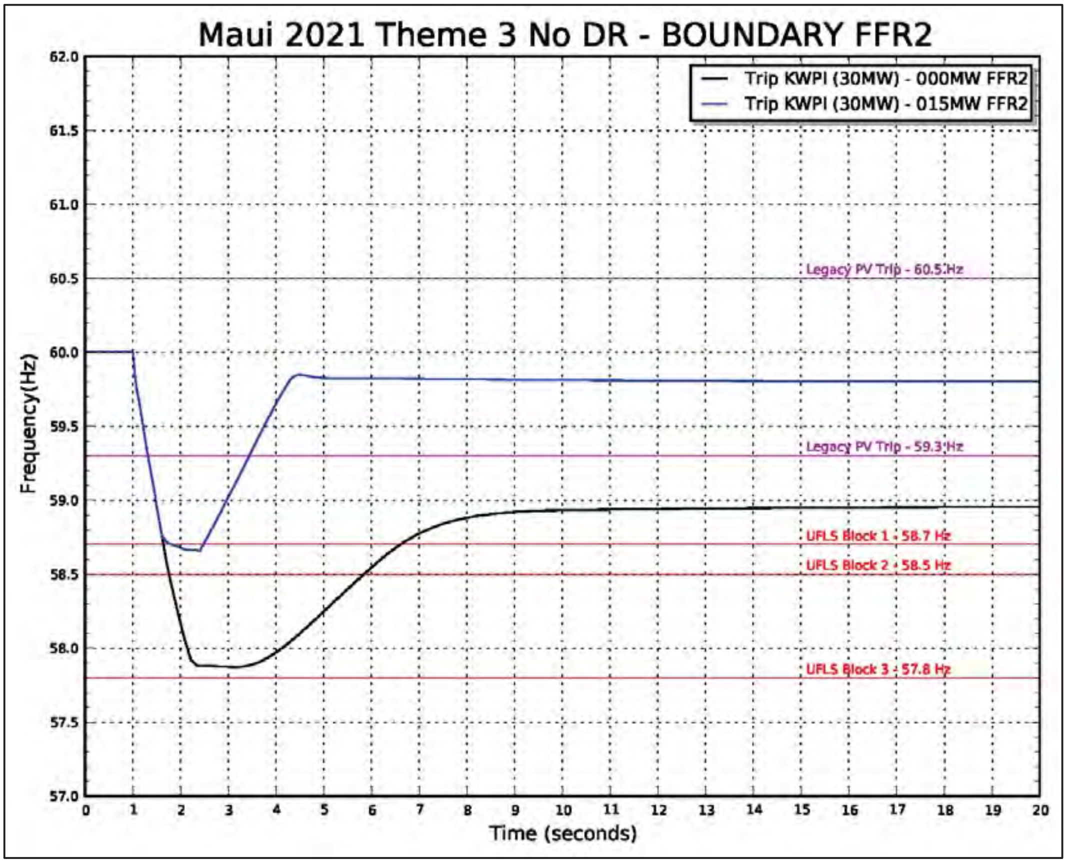

Figure O-228. Frequency Response Profile for FFR2 Boundary Hour

Figure O-228 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15 MW.

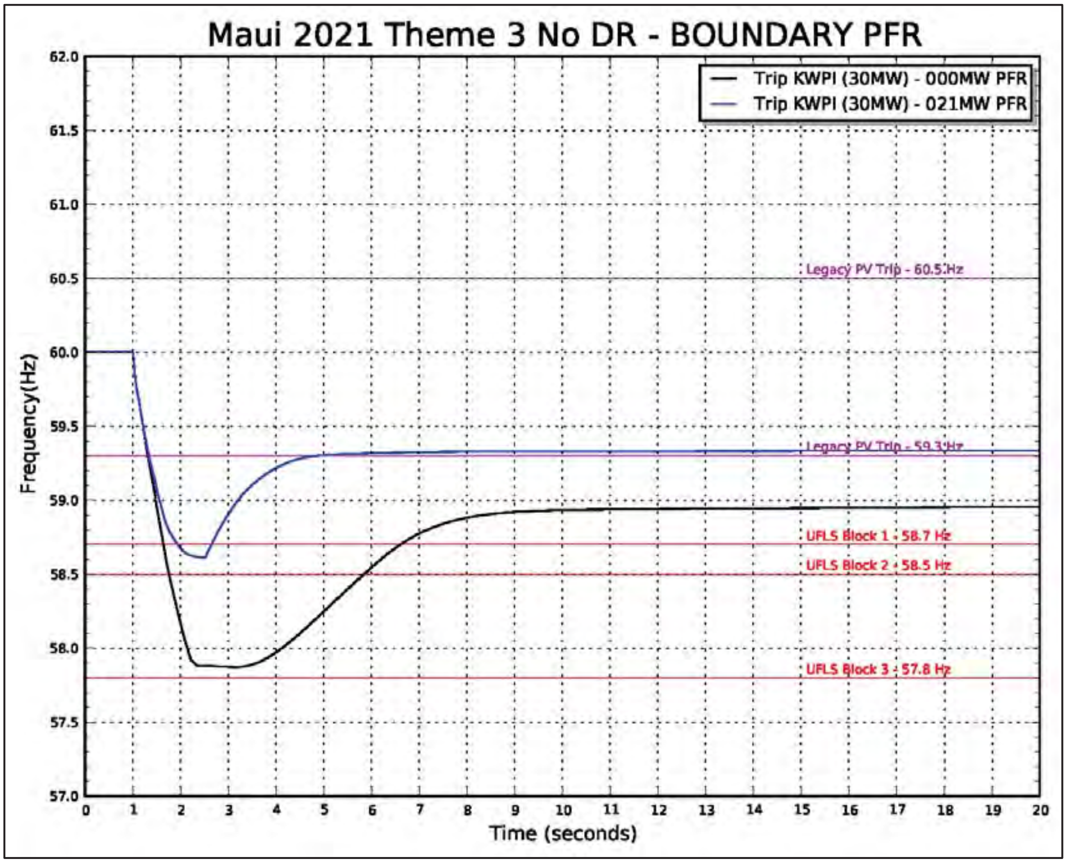

Figure O-229. Frequency Response Profile for PFR Boundary Hour

Figure O-229 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 22 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Mon 4/5/2021 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	12.0	8.0	6.1
Maalaea 15	13.0	4.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Total Wind	162					56		
-KWP	30	0				30		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				5		
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					5		
-Utility PV1	20	0				5		
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	128	0				102		
DER Grid Ex	8	0				4		
Total System MVA							29	
Total Kinetic Energy							305	
Total Load							188	
Total Thermal Generation							22	
Total Renewable Generation							167	
Total Generation							189	
Excess Generation							1	
Regulation Requirement							0	
Total Up Regulation							8	
Total Down Regulation							6	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		5.7
		60.5Hz Capacity		69.5		60.5Hz Output		55.2

Table O-97. Unit Commitment and Dispatch Fault Analysis 2021

Table O-97 shows the unit commitment and dispatch for the 69 kV fault analysis (4/5/21, 1:00 PM). The capacity from inverter-based generation is 102 MW.

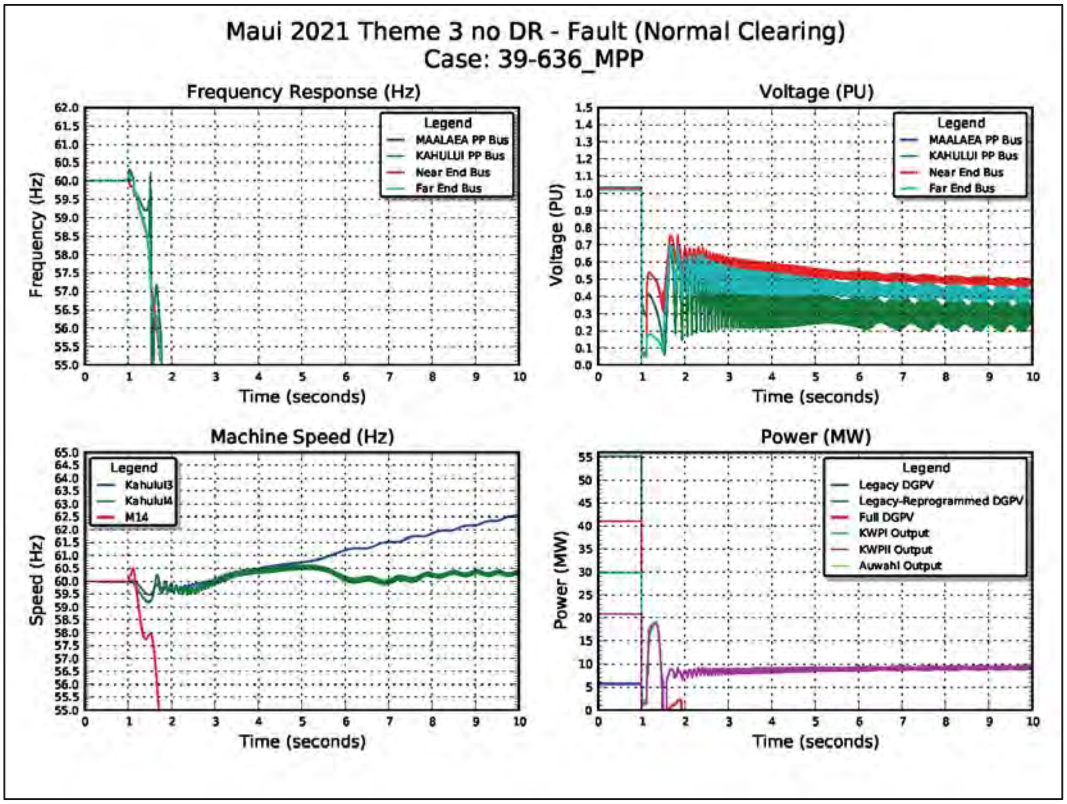

Figure O-230. System Performance Normally Cleared Fault

Figure O-230 shows the system performance for a normally cleared fault at the Maʻalaea end of the Maʻalaea-Waiinu circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 102 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

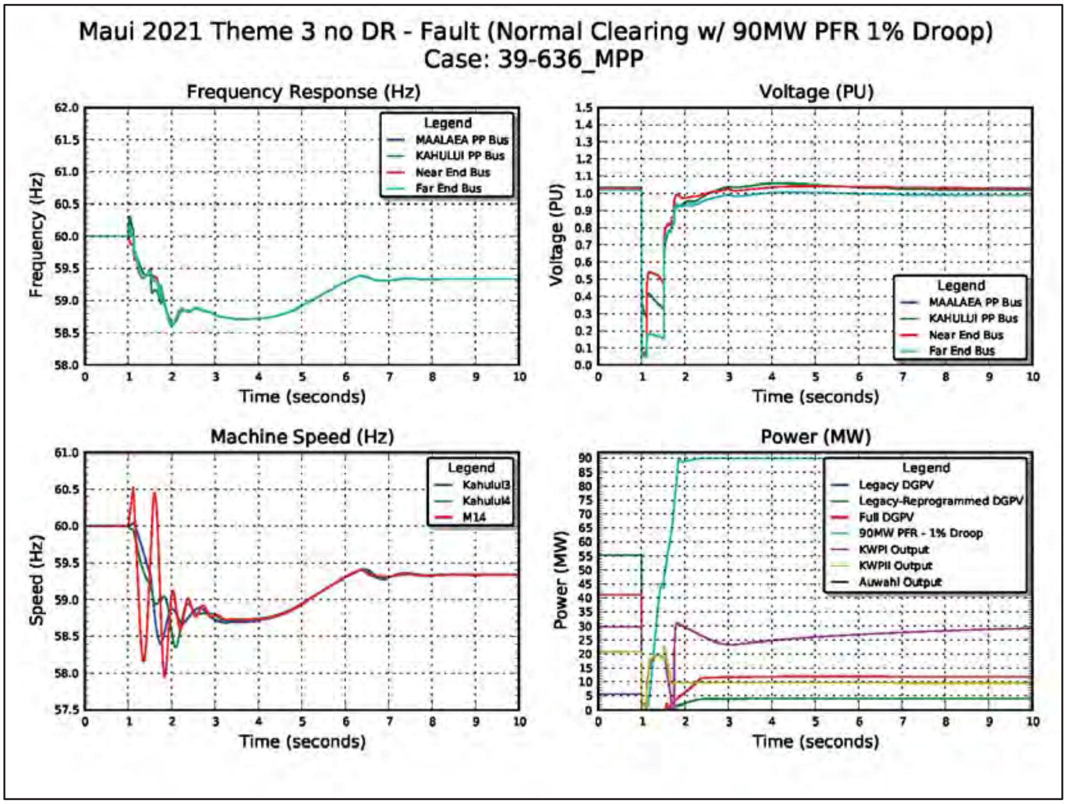

Figure O-231. Normally Cleared Fault Sensitivity 60 MW PFR

Figure O-231 shows system performance with the addition of the 90 MW of PFR at 1% droop response. For the purpose of this analysis, a 90 MW BESS was located at Maʻalaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 90 MW BESS. The aggregate response from synchronous units, the BESS resources, restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2021 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 90 MW PFR	Mitigation: 5-Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Unstable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-98. Summary of Results Fault Analysis 2021

Table O-98 shows the results of the 69 kV fault analysis with 90 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

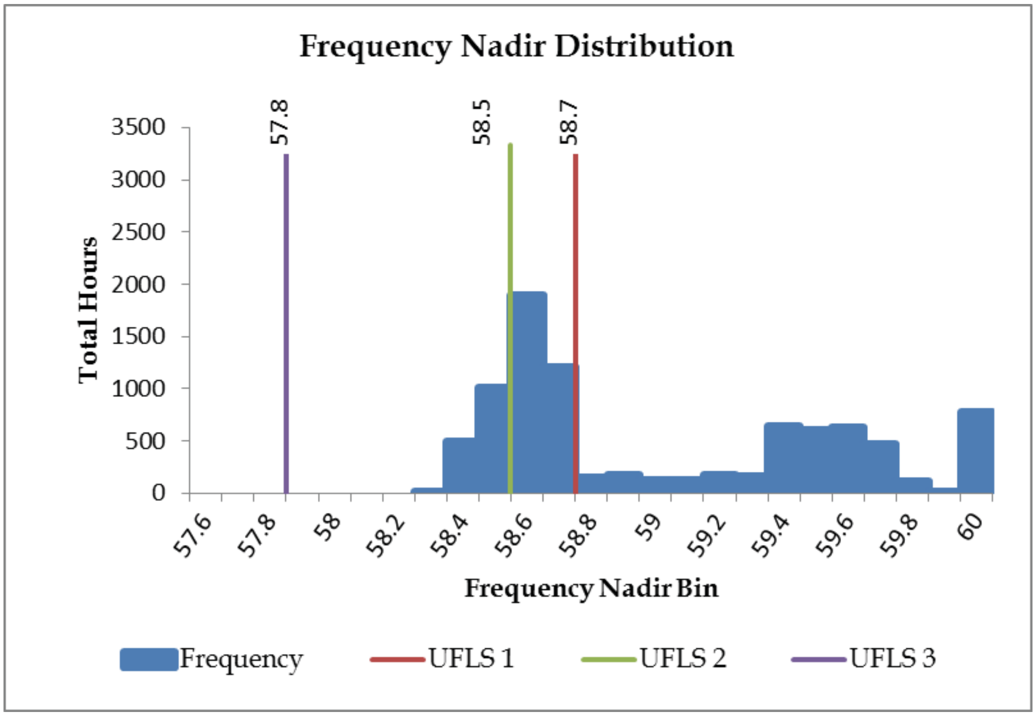

Figure O-232. Frequency Nadir Histogram for 2023

Figure O-232 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 1009 hours was 3:00 PM on Monday, May 15. The frequency nadir range for the typical hour is 58.5 - 58.6 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 2 hours was 4:00 AM on Thursday, November 2. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

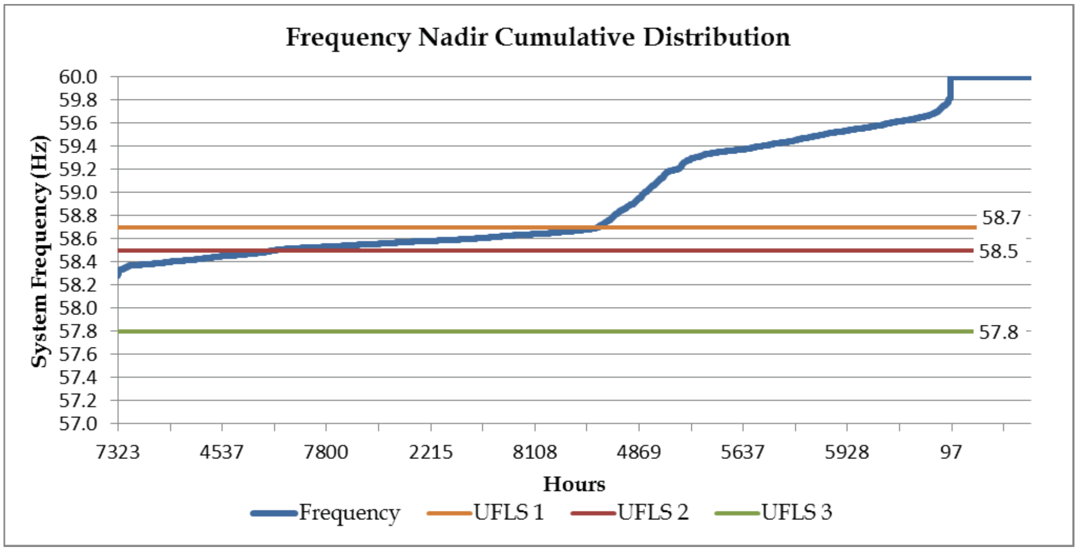

Figure O-233. Frequency Nadir Duration Curve 2023

Figure O-233 shows the frequency nadir duration curve for the Theme 3 resource plan in 2023. The system is at risk of exceeding the UFLS requirements of TPL-001 for 497 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 5/15/2023 Hour 15			Theme 3 - KWP I Trip Boundary Thu 11/2/2023 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87	8.0	12.0	2.0	7.0	13.0	1.0
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16	*Synchronous Condenser*			*Synchronous Condenser*		
Kahului 2	5.0	0.0	2.62	6.3	16	*Synchronous Condenser*			*Synchronous Condenser*		
Kahului 3	11.5	3.0	3.27	13.5	44	*Synchronous Condenser*			*Synchronous Condenser*		
Kahului 4	11.5	3.0	1.74	15.6	27	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					88			97		
-KWP	30	0				25			30		
-Auwahi	21	0				6					
-KWPII	21	0				21			19		
-New Wind 1	30	0				30			24		
-New Wind 2	30	0				6			24		
-New Wind 3	30	0									
Total Utility PV	80					5					
-Utility PV1	20	0				5					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				77					
DER Grid Ex	10	0				5					
Total System MVA						127			25		
Total Kinetic Energy						295			295		
Total Load						182			104		
Total Thermal Generation						8			7		
Total Renewable Generation						175			97		
Total Generation						183			104		
Excess Generation						1			0		
Regulation Requirement						0			0		
Total Up Regulation						0			0		
Total Down Regulation						0			0		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		4.2	59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		40.8	60.5Hz Output		0.0

Table O-99. Unit Commitment and Dispatch 2023

Table O-99 shows the unit commitment and dispatch for the typical hour (5/15/23, 3:00 PM) and boundary hour (11/2/23, 4:00 AM).

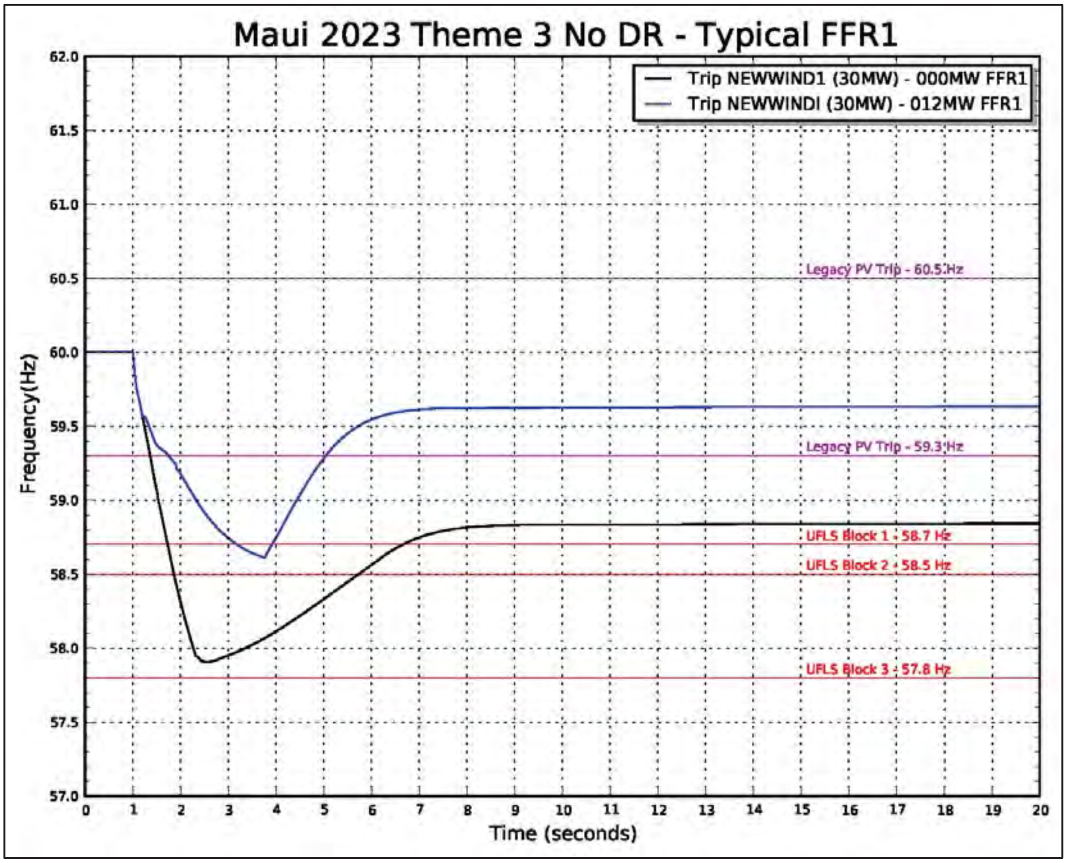

Figure O-234. Frequency Response Profile for FFR1 Typical Hour

Figure O-234 shows the frequency response profile for a windfarm trip at 30 MW for a typical hour. System kinetic energy is 295 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.2 MW. With no FFR, the frequency nadir is 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 12 MW.

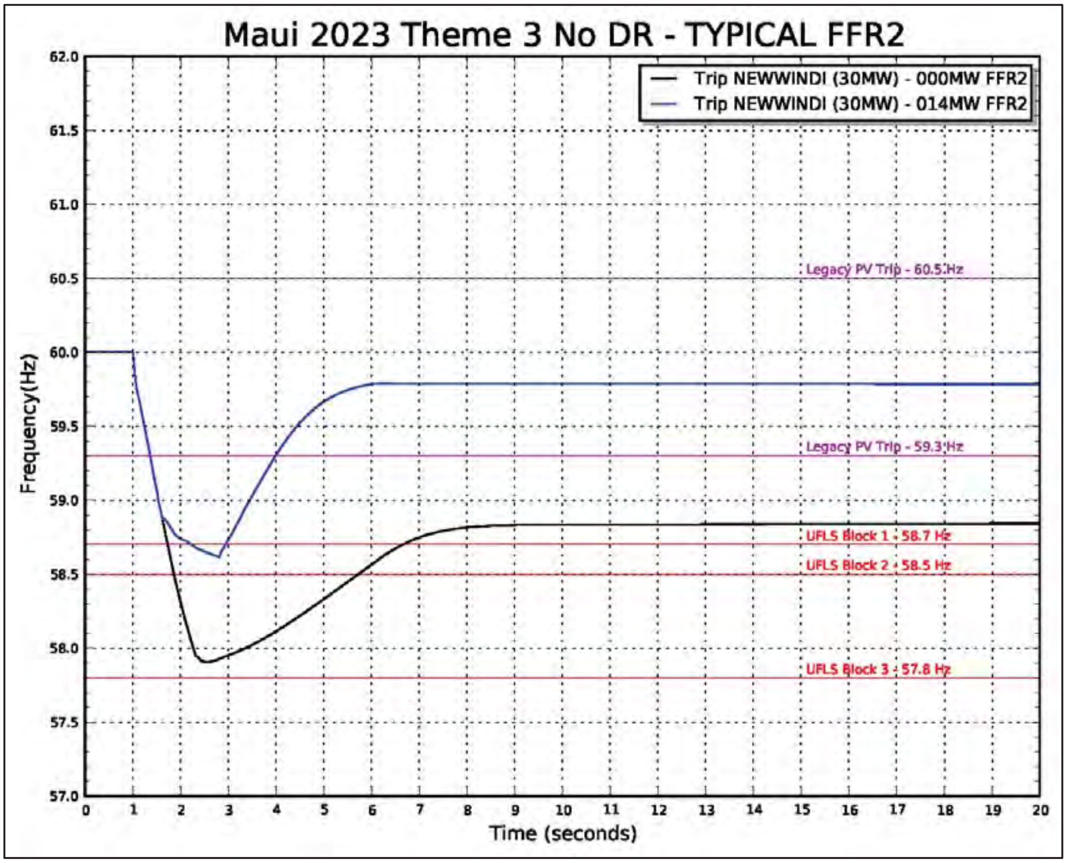

Figure O-235. Frequency Response Profile for FFR2 Typical Hour

Figure O-235 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 14 MW.

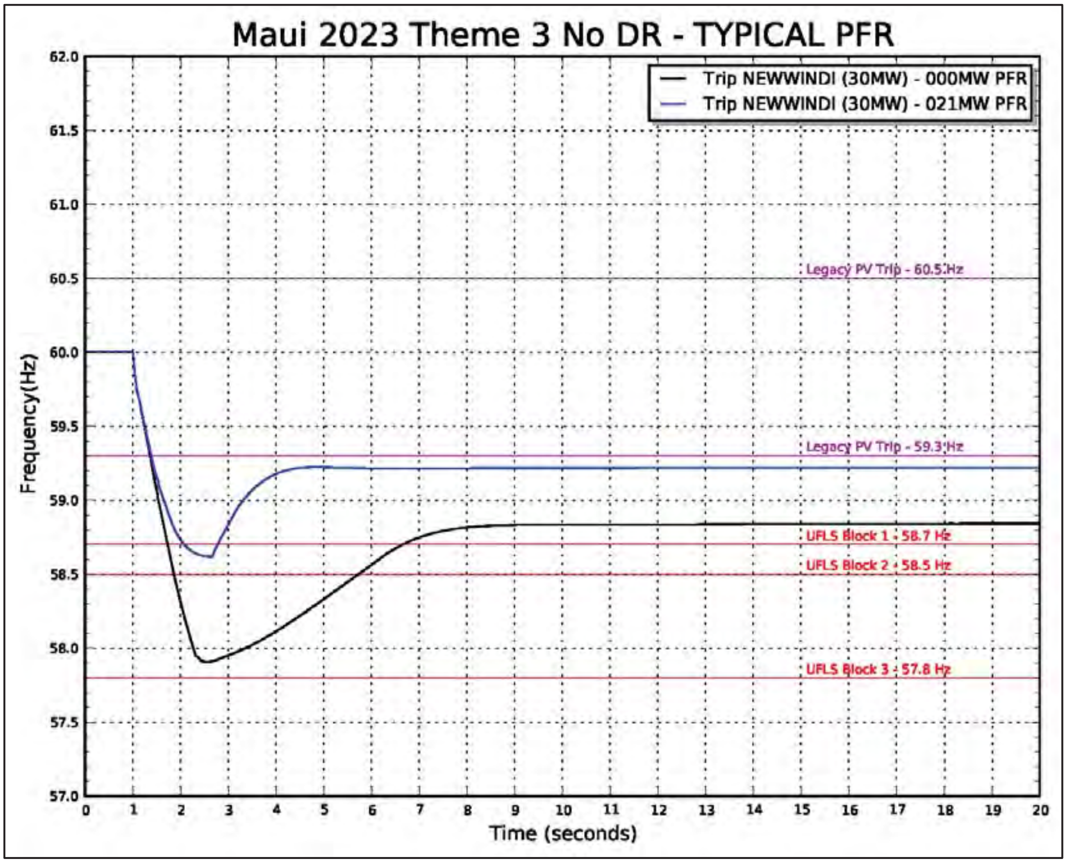

Figure O-236. Frequency Response Profile for PFR Typical Hour

Figure O-236 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW.

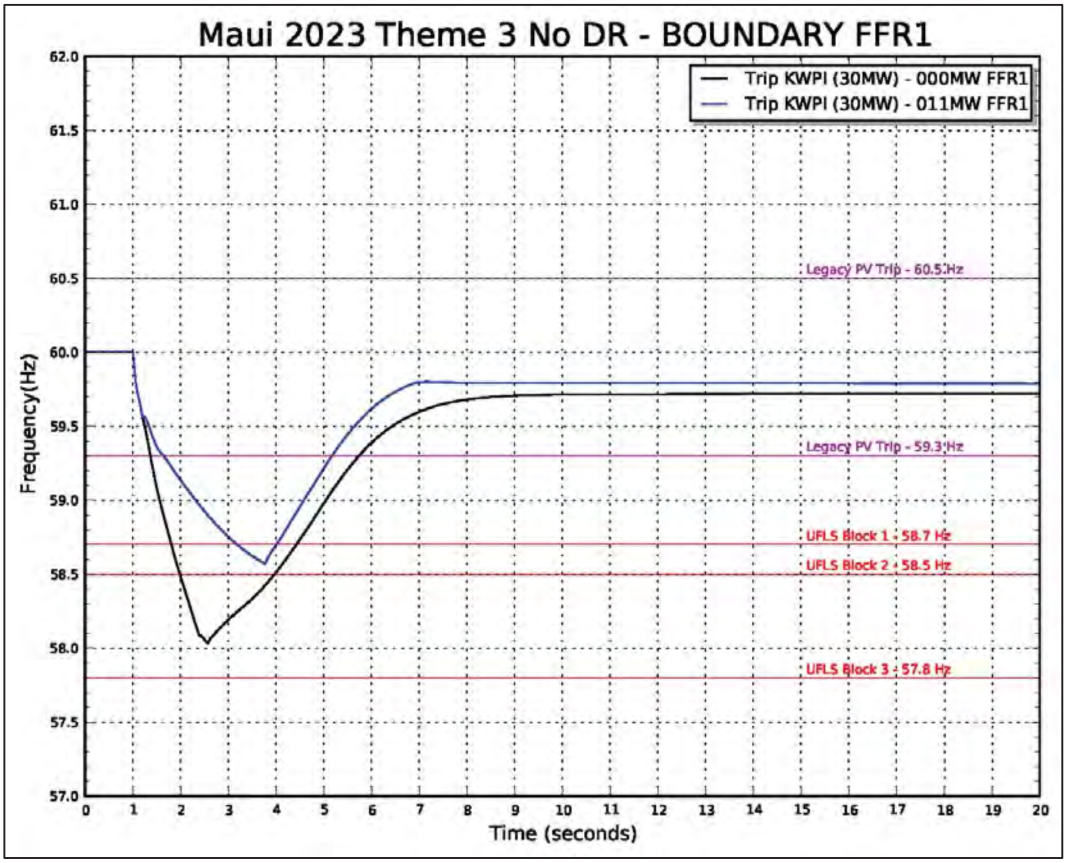

Figure O-237. Frequency Response Profile for FFR1 Boundary Hour

Figure O-237 shows the frequency response profile for a KWP 1 trip at 30 MW for a boundary hour. System kinetic energy is 295 MW-sec. With no FFR, the frequency nadir approaches 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11 MW.

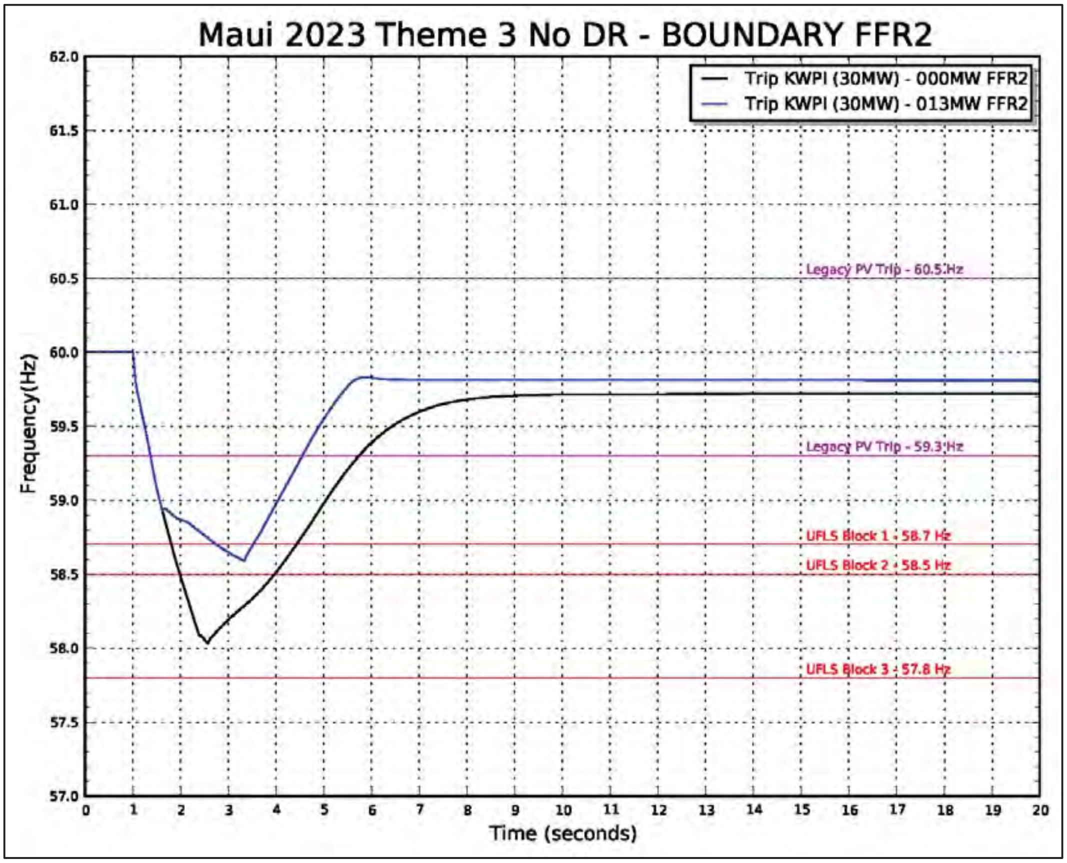

Figure O-238. Frequency Response Profile for FFR2 Boundary Hour

Figure O-238 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

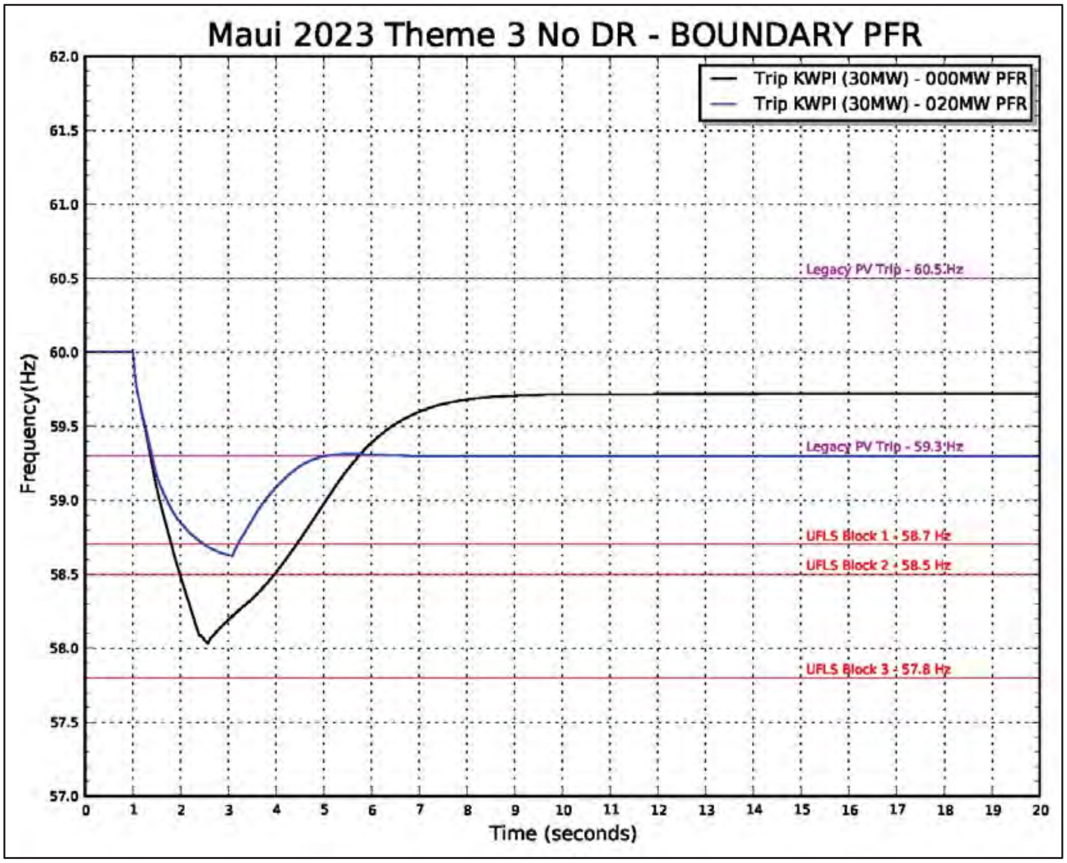

Figure O-239. Frequency Response Profile for PFR Boundary Hour

Figure O-239 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 20 MW.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data that represents a boundary condition.

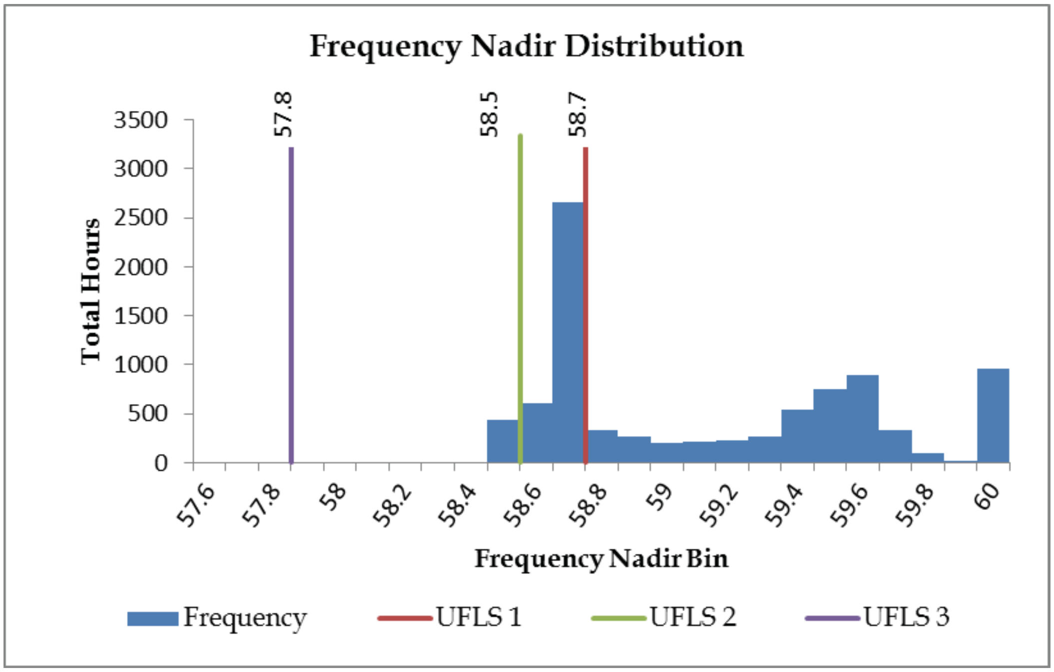

Figure O-240. Frequency Nadir Histogram for 2030

Figure O-240 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. A boundary hour was selected from a maximum distribution of 429 hours was 4:00 AM on Thursday, May 31. The frequency nadir range for the typical hour is 58.3 - 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

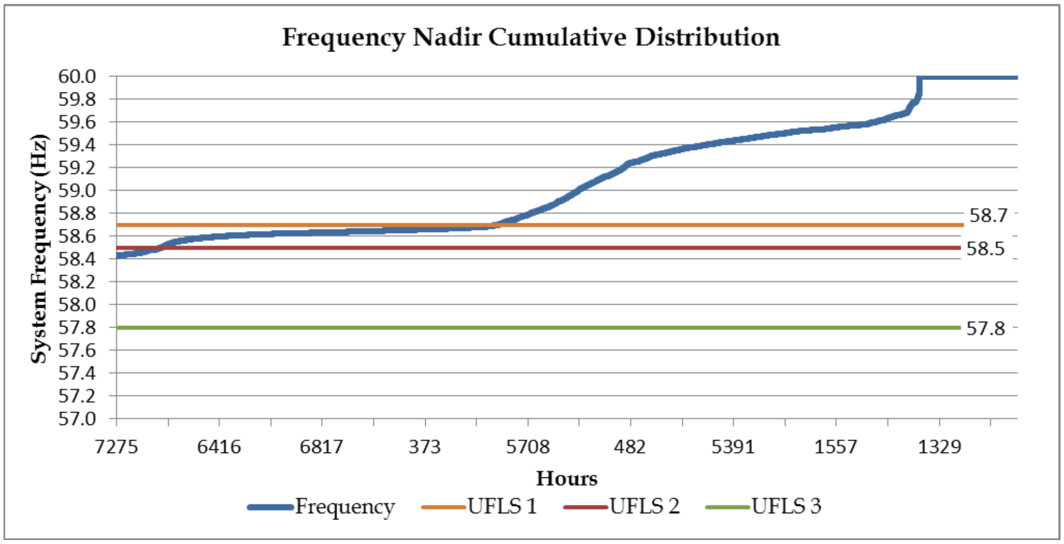

Figure O-241. Frequency Nadir Duration Curve 2030

Figure O-241 shows the frequency nadir duration curve for the Theme 3 resource plan in 2030. The system is at risk of exceeding the UFLS requirements of TPL-001 for 429 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Boundary Thu 10/31/2030 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	7.0	3.48	25.0	87	7.0	13.0	0.0
Geothermal 1	20.0	5.0	3.48	25.0	87	6.0	14.0	1.0
Geothermal 2	20.0	5.0	3.48	25.0	87	5.0	15.0	0.0
Maalaea 14	20.0	5.9	2.02	26.8	58			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
ICE9_1	9.0	4.6	1.00	11.3	11			
ICE9_2	9.0	4.6	1.00	11.3	11			
Kahului 1	0.0	0.0	2.62	6.3	16	*Synchronous Condenser*		
Kahului 2	0.0	0.0	2.62	6.3	16	*Synchronous Condenser*		
Kahului 3	0.0	0.0	3.27	13.5	44	*Synchronous Condenser*		
Kahului 4	0.0	0.0	1.74	15.6	27	*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Total Wind	162					81		
-KWP	30	0				30		
-Auwahi	21	0						
-KWPII	21	0				19		
-New Wind 1	30	0				16		
-New Wind 2	30	0				16		
-New Wind 3	30	0						
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	138.9	0						
DER Grid Ex	16.0	0						
Total System MVA						177		
Total Kinetic Energy						469		
Total Load						99		
Total Thermal Generation						18		
Total Renewable Generation						81		
Total Generation						99		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						0		
Total Down Regulation						0		
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		0.0
	60.5Hz Capacity			29.9		60.5Hz Output		0.0

Table O-100. Unit Commitment and Dispatch 2030

Table O-100 shows the unit commitment and dispatch for the boundary hour (10/31/2030, 4:00AM).

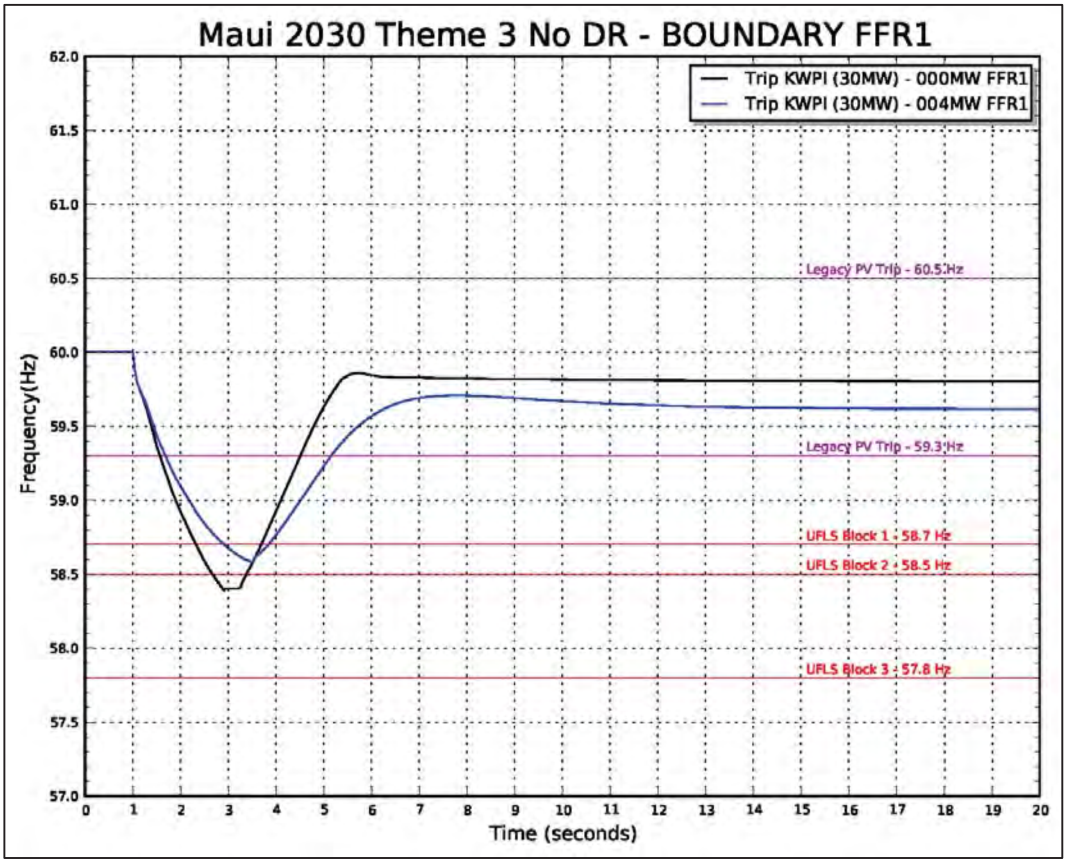

Figure O-242. Frequency Response Profile for FFR1 Boundary Hour

Figure O-242 shows the frequency response profile for a KWP1 trip at 30 MW for a boundary hour. System kinetic energy is 469 MW-sec. With no FFR, the frequency nadir is 58.4 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 4 MW.

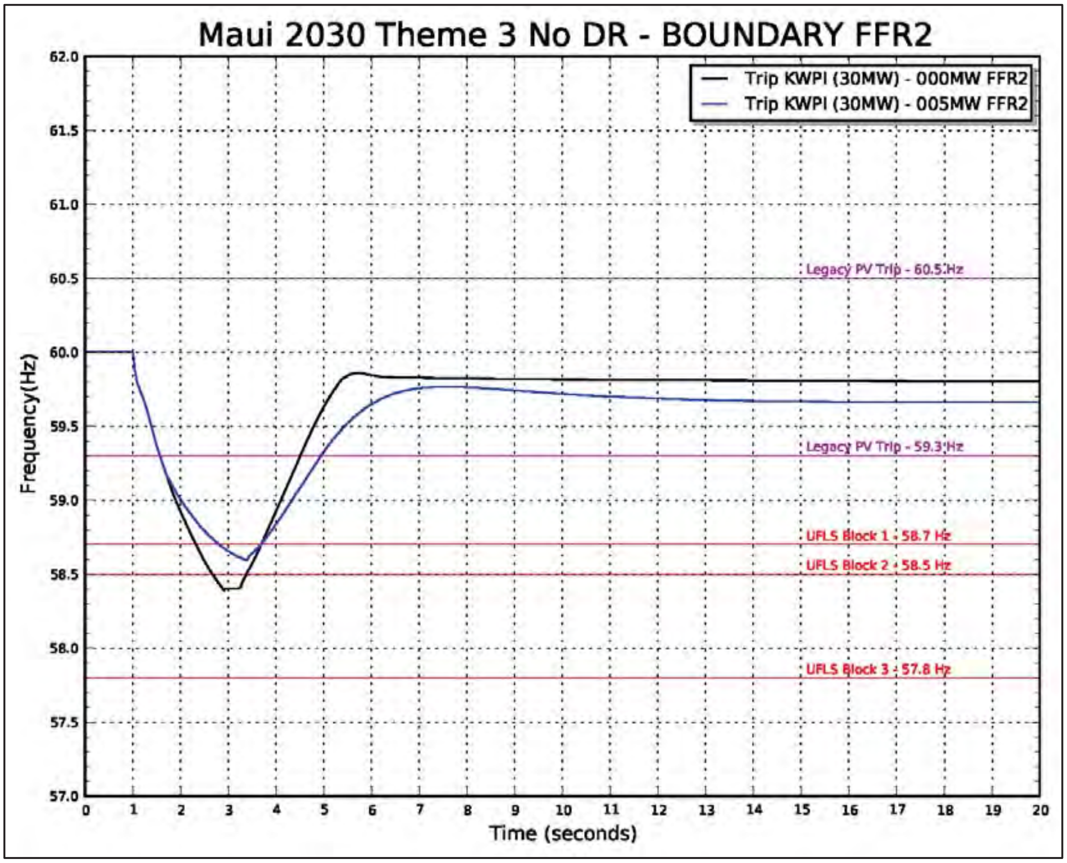

Figure O-243. Frequency Response Profile for FFR2 Typical Hour

Figure O-243 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

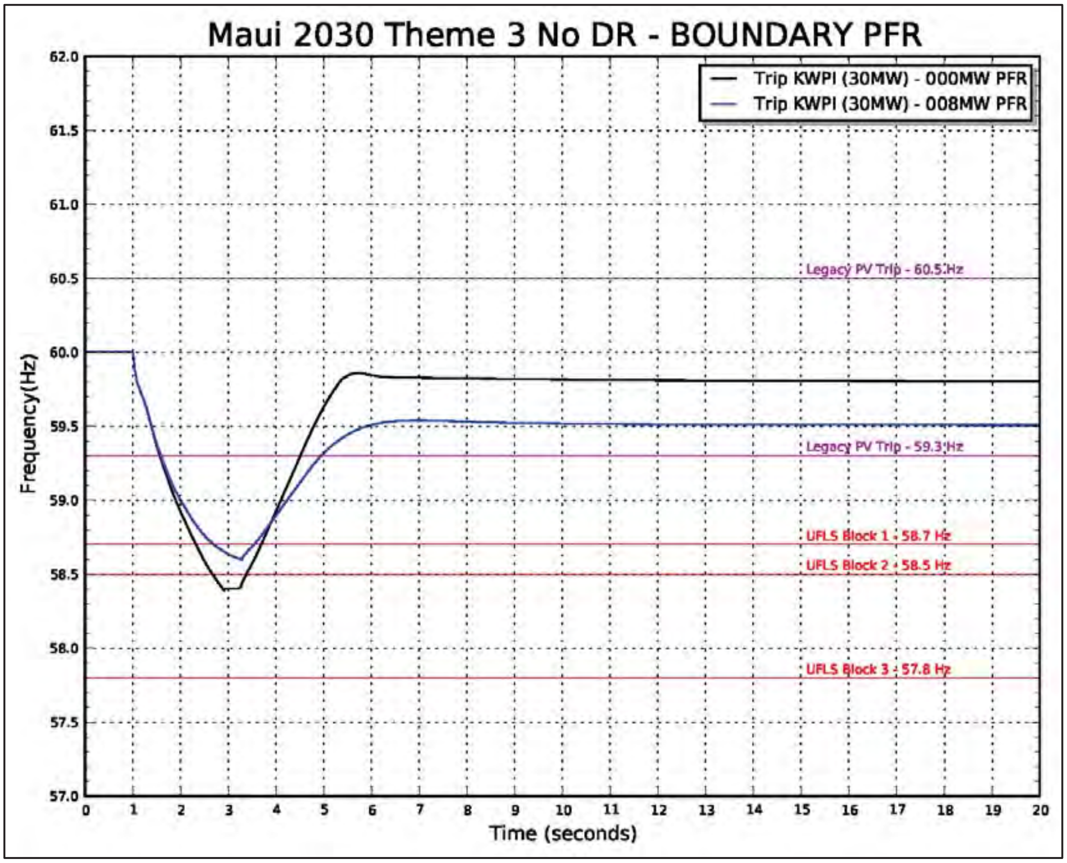

Figure O-244. Frequency Response Profile for PFR Boundary Hour

Figure O-244 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 8 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data to represent a boundary condition.

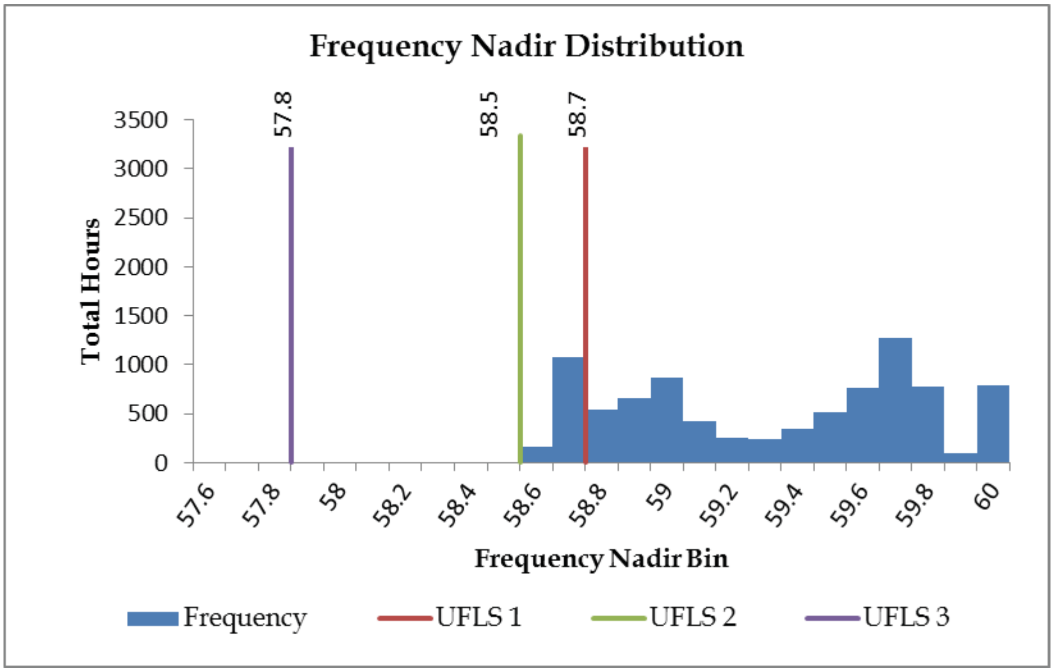

Figure O-245. Frequency Nadir Histogram for 2045

Figure O-245 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The system is in compliance with TPL-001 for the entire year.

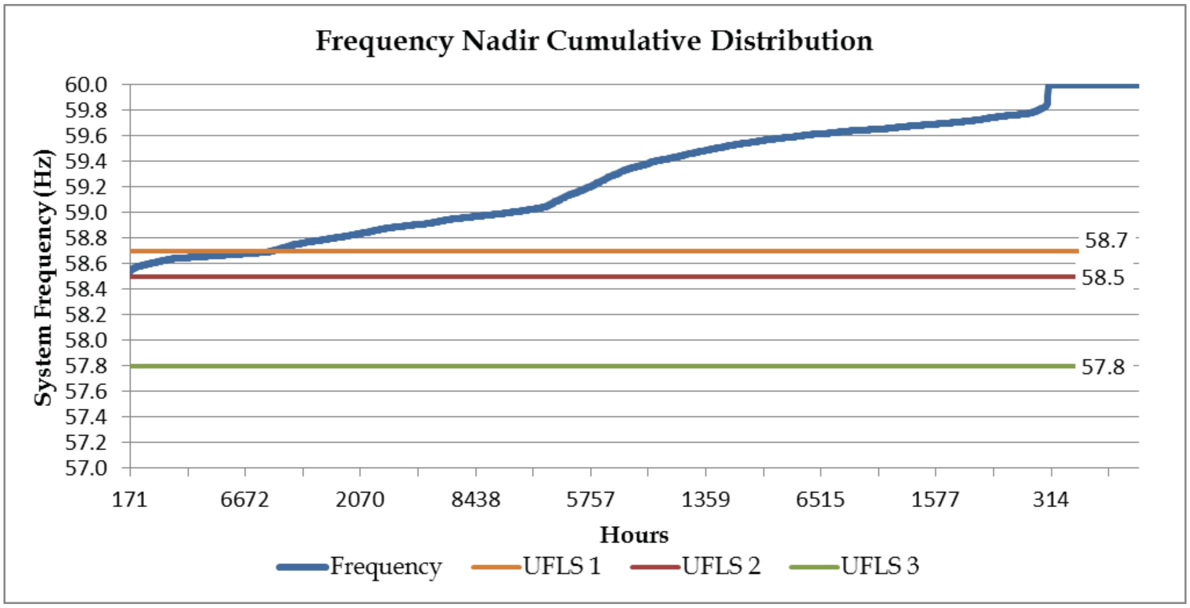

Figure O-246. Frequency Nadir Duration Curve 2045

Figure O-246 shows the frequency nadir duration curve for the Theme 3 resource plan in 2045.

Unit	Unit Ratings					Theme 3 - KWP I Trip Boundary Thu 4/11/2045 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Biomass 2	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Biomass 3	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Geothermal 1	20.0	5.0	3.28	25.0	82	6.0	14.0	2.7
Geothermal 2	20.0	5.0	3.48	25.0	87	6.0	14.0	2.5
Maalaea 14	20.0	5.9	2.02	26.8	58			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
ICE9_1	9.0	4.6	1.00	11.3	11			
ICE9_2	9.0	4.6	1.00	11.3	11			
Kahului 1	0.0	0.0	2.62	6.3	16	*Synchronous Condenser*		
Kahului 2	0.0	0.0	2.62	6.3	16	*Synchronous Condenser*		
Kahului 3	0.0	0.0	3.27	13.5	44	*Synchronous Condenser*		
Kahului 4	0.0	0.0	1.74	15.6	27	*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Total Wind	162					82		
-KWP	30	0				28		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				11		
-New Wind 2	30	0				11		
-New Wind 3	30	0				11		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	159.7	0						
DER Grid Ex	37.138	0						
Total System MVA						532		
Total Kinetic Energy						638		
Total Load						114		
Total Thermal Generation						33		
Total Renewable Generation						82		
Total Generation						115		
Excess Generation						1		
Regulation Requirement						0		
Total Up Regulation						0		
Total Down Regulation						0		
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-101. Unit Commitment and Dispatch 2045

Table O-101 shows the unit commitment and dispatch for the boundary hour (4/11/2045, 4:00 AM).

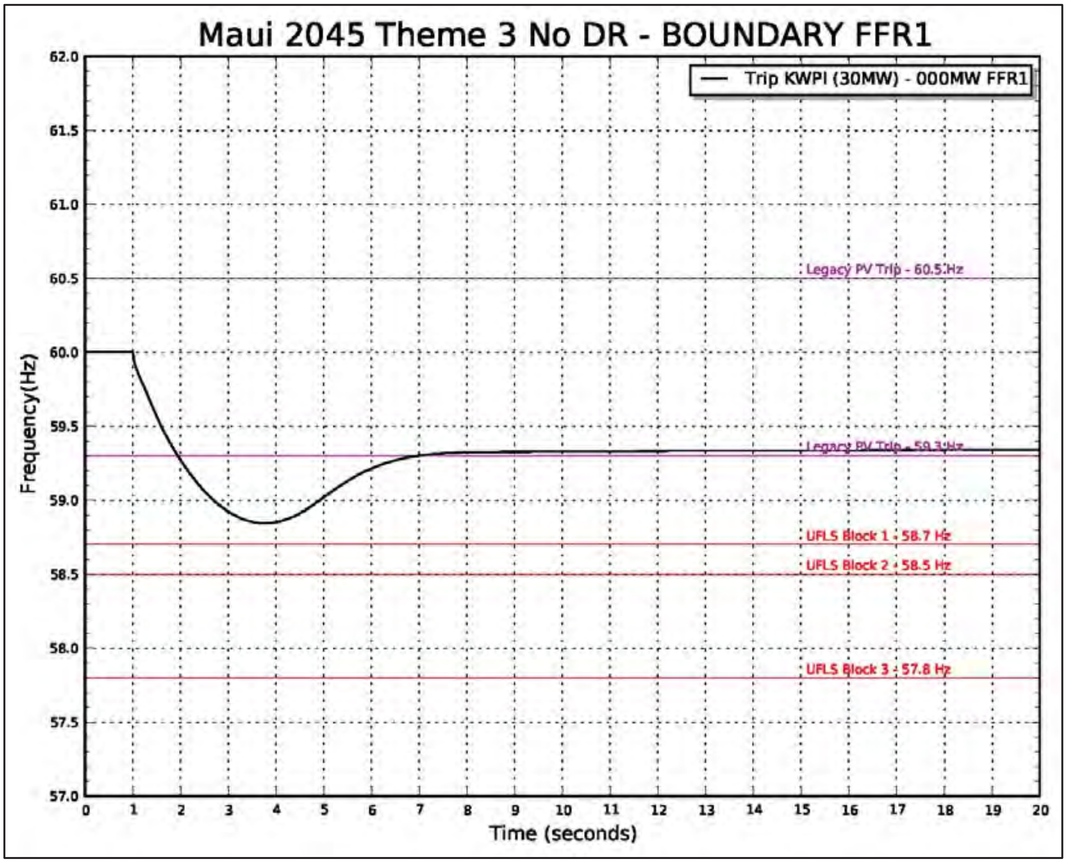

Figure O-247. Frequency Response Profile for FFR1 Boundary Hour

Figure O-247 shows the frequency response profile for a KWP 1 Trip at 30 MW for a boundary hour. System kinetic energy is 638 MW-sec which is significantly higher than previous years due to the addition of the firm renewable resources. The system is in compliance with TPL-001 so no additional resources are required.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021. Maui does not have FFR2 capacities in their Demand Response portfolio.

2019

System security analysis performed on the Post April DR resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Maui transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirements of 73 MVA on the 69 kV system and 29 MVA on the 23 kV system. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Tue 8/20/2019 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.8	12.3	2.9
Maalaea 15	13.0	5.0	2.46	18.5	46	7.4	5.6	2.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.9	12.2	3.0
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					63		
-KWP	30	0				23		
-Auwahi	21	0				20		
-KWPII	21	0				20		
Station PV	6.74	0				6		
DGPV	121	0				92		
Total System MVA						117		
Total Kinetic Energy						328		
Total Load						192		
Total Thermal Generation						31		
Total Renewable Generation						161		
Total Generation						193		
Excess Generation						1		
Regulation Requirement						0		
Total Up Regulation						30		
Total Down Regulation						8		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		
	60.5Hz Capacity			69.5		60.5Hz Output		

Table O-102. Unit Commitment and Dispatch 2019 QV Analysis

Table O-102 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Tue 8/20/2019 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	4.2	-0.1	4.2
Maalaea 15	2.9	0.0	3.6	-0.7	3.6
Maalaea 16	4.1	0.0	4.3	-0.2	4.3
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Sml Sync Condenser 1	16.0	-16.0	11.0	5.0	27.0
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.4	13.1	1.6
-Auwahi	6.5	-6.5	0.9	5.6	7.4
-KWPII	10.2	0.0	1.4	8.8	1.4
-New Wind 1	9.9	0.0			
-New Wind 2	9.9	0.0			
-New Wind 3	9.9	0.0			
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			26.0		
Total Renewable MVAR Generation			3.7		
Total Cap Bank MVAR			51.8		
Charging MVAR			5.0		
Total MVAR Supply			86.5		
Total MVAR Load			32.3		
Total MVAR Losses			26.9		
Excess MVAR Generation			27.4		
Total MVAR Supply Capability				45	
Total MVAR Absorb Capability					42.0

Table O-103. MVAR Capability 2019 QV Analysis

Table O-103 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
101	Kahului PP-Wailuku 23 kV
102	Maalaea-Kihei
104	Maalaea-Waiinu
113	Wailea-Auwahi 69 KV
114	Wailea-Kihei 69 kV

Table O-104. N-1 Contingencies 2019 QV Analysis

Table O-104 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

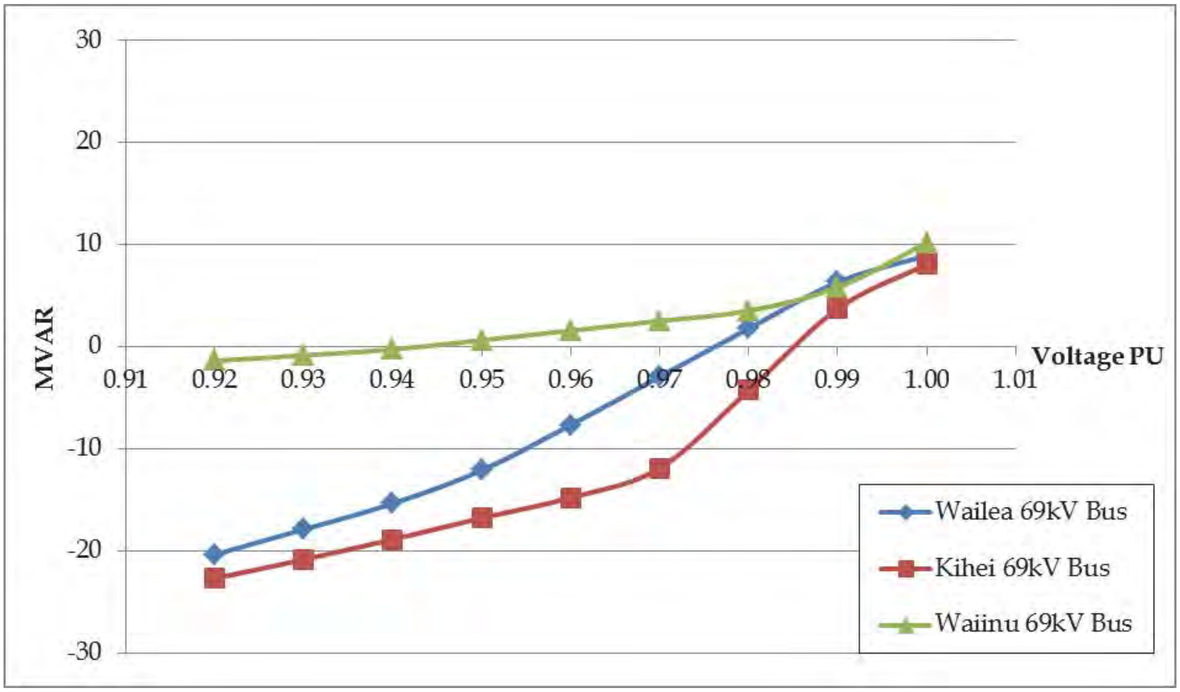

Figure O-248. QV Curves 2019

Figure O-248 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	9	113	6	113	2	113	-3	113	-8	113	-12	114	-15	114	-18	114	-20
35	Kihei 69 kV Bus	113	8	113	4	113	-4	113	-12	102	-15	102	-17	102	-19	102	-21	102	-23
636	Waiinu 69 kV Bus	101	10	115	6	104	4	104	3	104	2	104	1	104	0	104	-1	104	-1

Table O-105. Summary of Results 2019 QV Analysis

Table O-105 shows the results of the QV analysis for 2019. The Waiinu Bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirement for the system is met.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data that represents a typical and boundary condition.

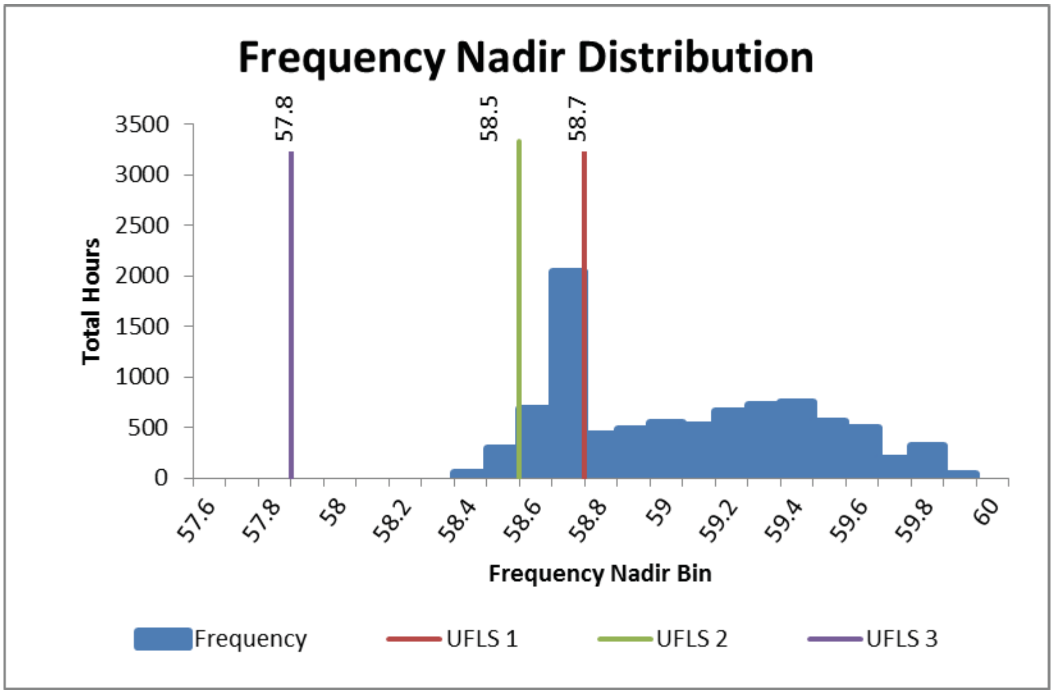

Figure O-249. Frequency Nadir Histogram for 2019

Figure O-249 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 288 hours was 12:00 PM on Monday, April 8. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 51 hours was 3:00 AM on Wednesday, June 5. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

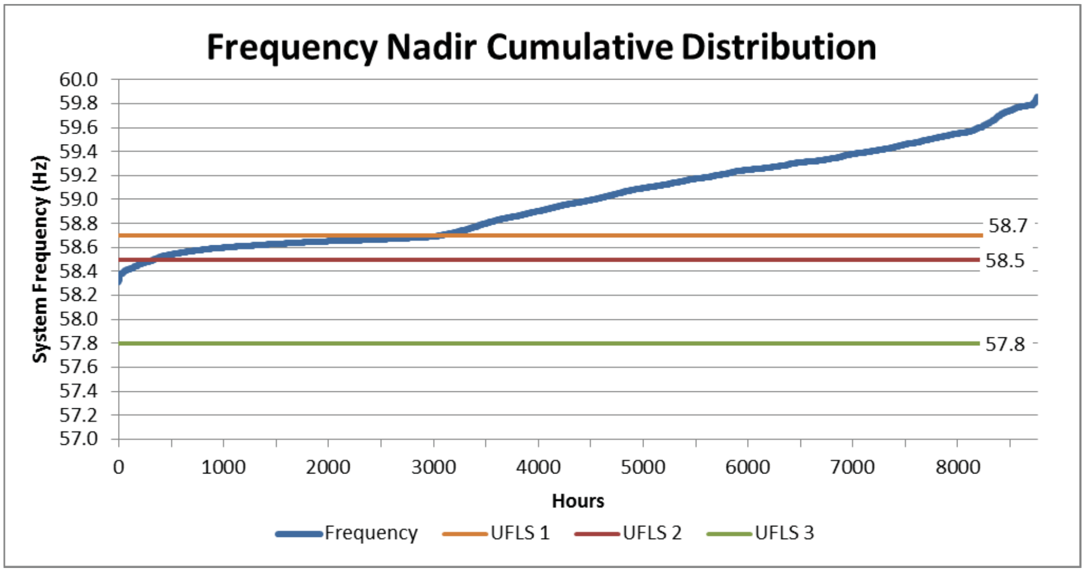

Figure O-250. Frequency Nadir Duration Curve 2019

Figure O-250 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 340 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Mon 4/8/2019 Hour 12			DR - KWP I Trip Boundary Wed 6/5/2019 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.1	7.4	1.1	8.1	3.4	5.1
Kahului 4	11.5	3.0	3.48	15.6	54	4.7	6.8	1.7	5.4	6.1	2.4
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0			
Maalaea 15	13.0	5.0	2.46	18.5	46				6.5	6.5	1.5
Maalaea 16	21.1	5.9	2.02	26.8	54	8.9	12.2	3.0	21.1	0.0	15.2
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6			
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	72					50			57		
-KWP	30	0				30			30		
-Auwahi	21	0							7		
-KWPII	21	0				21			20		
Station PV	6.74	0				6					
DGPV	121	0				85					
Total System MVA						106			90		
Total Kinetic Energy						299			270		
Total Load						177			98		
Total Thermal Generation						32			41		
Total Renewable Generation						142			57		
Total Generation						174			98		
Excess Generation						-3			-1		
Regulation Requirement						0			0		
Total Up Regulation						24			6		
Total Down Regulation						10			17		
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.2 69.5		59.3Hz Output 60.5Hz Output		4.7 45.1	59.3Hz Output 60.5Hz Output		

Table O-106. Unit Commitment and Dispatch 2019

Table O-106 shows the unit commitment and dispatch for the typical hour (4/8/19, 12:00 PM) and boundary hour (6/5/19, 3:00 AM).

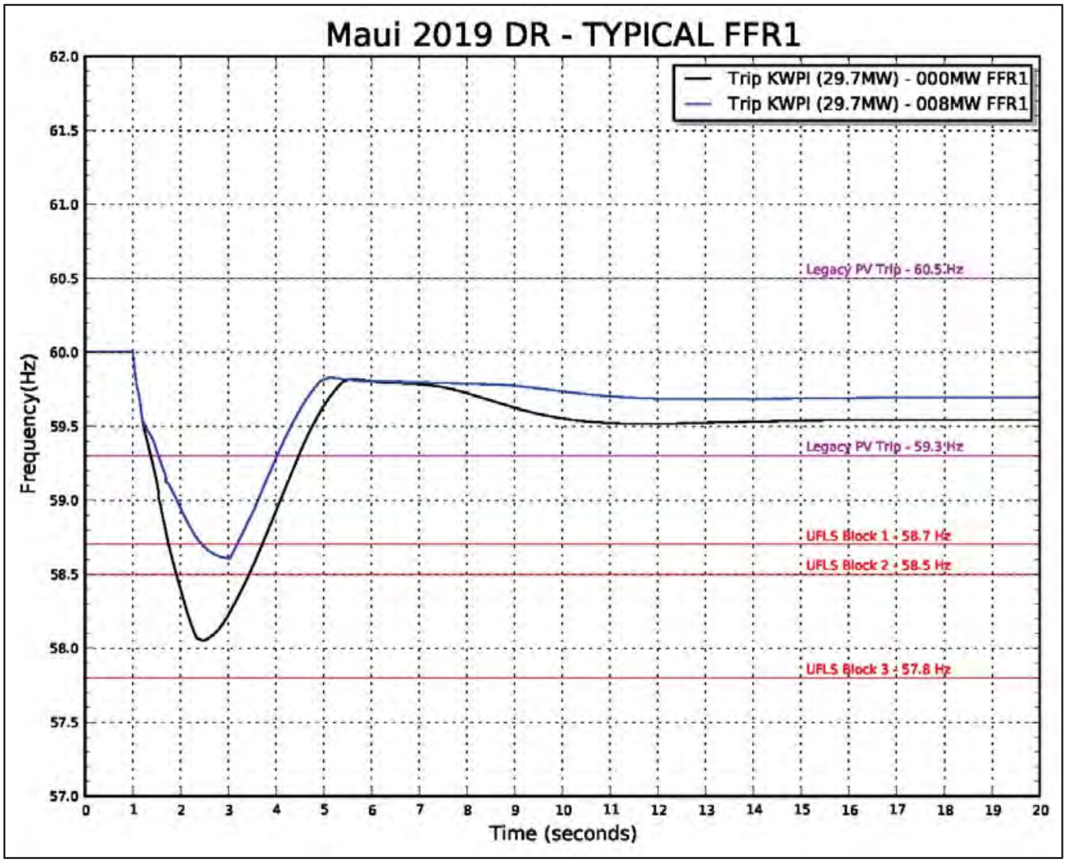

Figure O-251. Frequency Response Profile for FFR1 Typical Hour

Figure O-251 shows the frequency response profile for a KWP I trip at 29.7 MW for a typical hour. System kinetic energy is 299 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.7 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

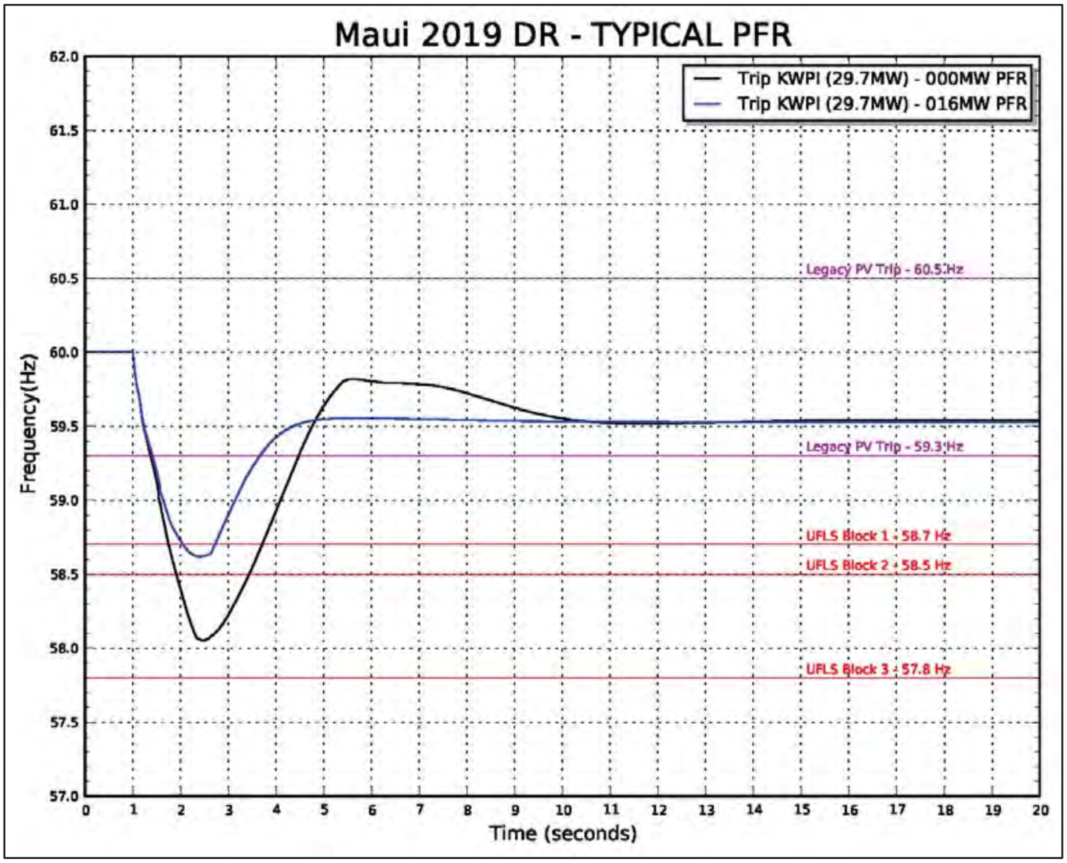

Figure O-252. Frequency Response Profile for PFR Typical Hour

Figure O-252 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 16 MW. This is in addition to the 24 MW of upward regulation from thermal generation.

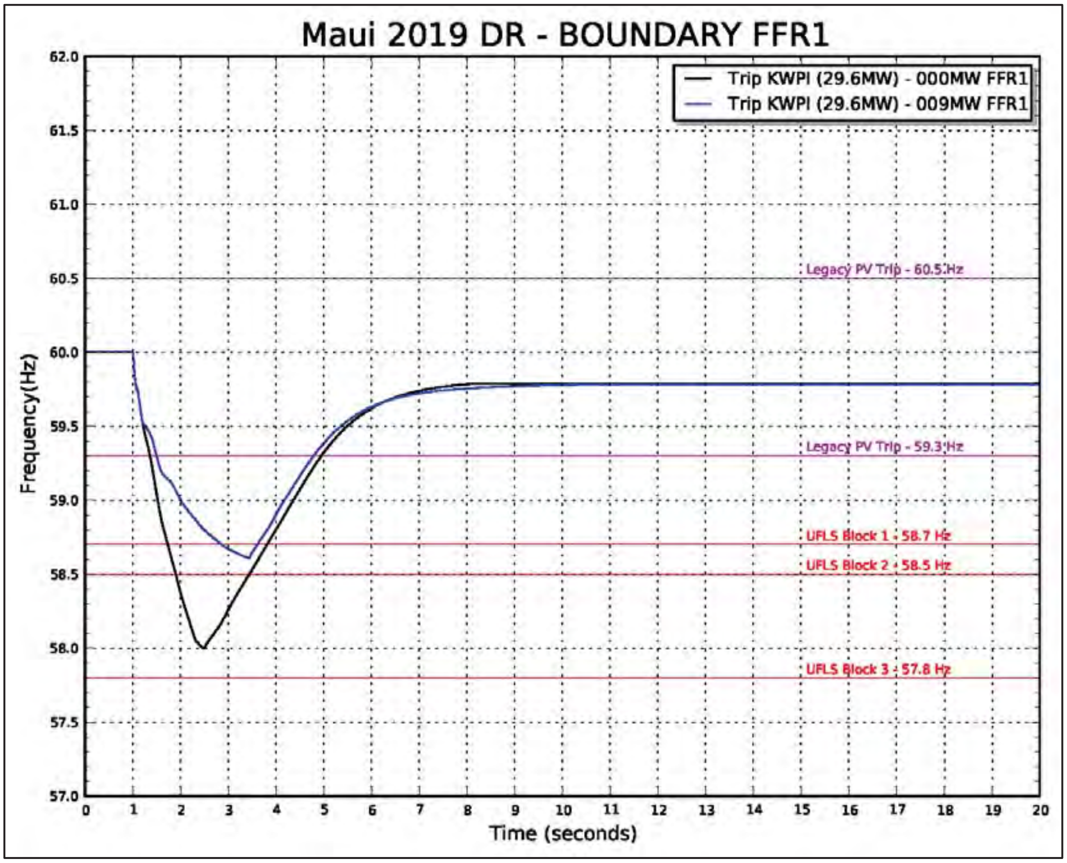

Figure O-253. Frequency Response Profile for FFR1 Boundary Hour

Figure O-253 shows the frequency response profile for a KWP 1 trip at 29.6 MW for a boundary hour. System kinetic energy is 270 MW-sec. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

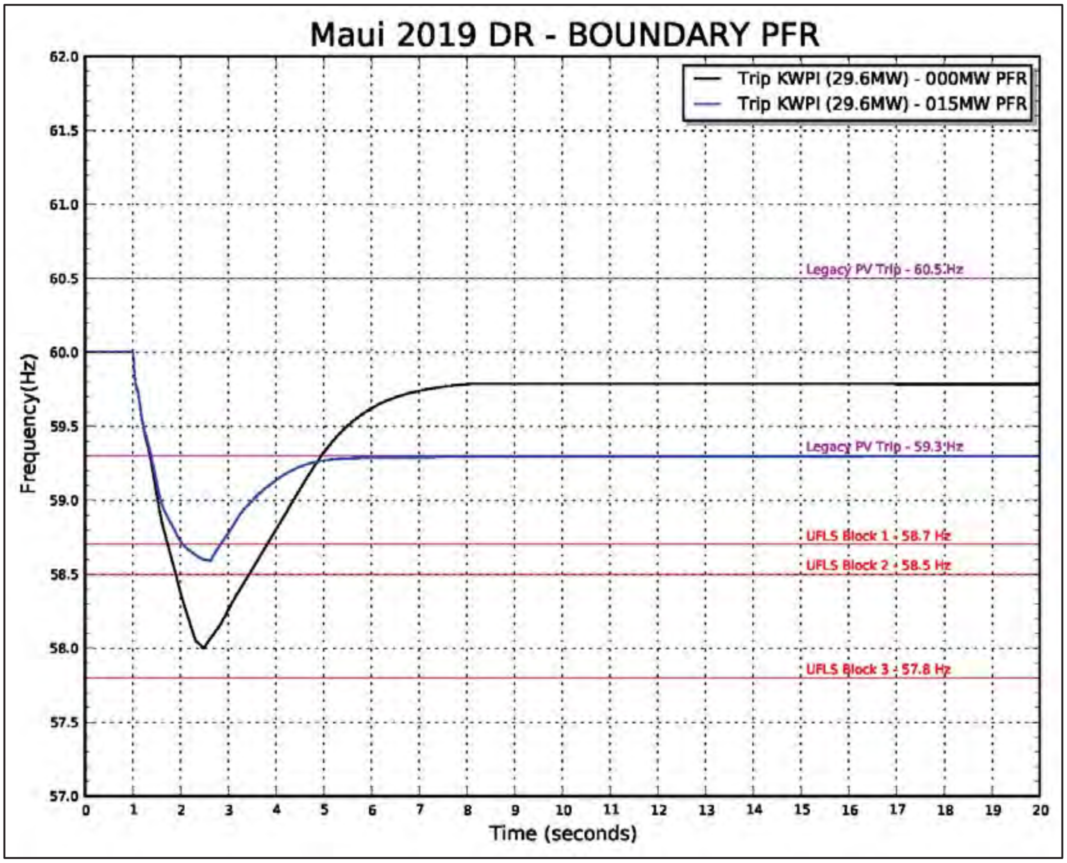

Figure O-254. Frequency Response Profile for PFR Boundary Hour

Figure O-254 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 16 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Sat 5/11/2019 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	28.8	58	10.2	11.0	4.2
Maalaea 15	13.0	5.0	2.46	18.5	46	9.1	3.9	4.1
Maalaea 16	21.1	5.9	2.02	26.8	54	12.0	9.2	6.1
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					14		
-KWP	30	0						
-Auwahi	21	0				14		
-KWPII	21	0						
Station PV	6.74	0				6		
DGPV	121	0				96		
Total System MVA							126	
Total Kinetic Energy							344	
Total Load							162	
Total Thermal Generation							43	
Total Renewable Generation							117	
Total Generation							159	
Excess Generation							-3	
Regulation Requirement							0	
Total Up Regulation							41	
Total Down Regulation							18	
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.2 69.5		59.3Hz Output 60.5Hz Output		5.3 50.7

Table O-107. Unit Commitment and Dispatch Fault Analysis 2019

Table O-107 shows the unit commitment and dispatch for the 69 kV fault analysis (5/11/19, 1:00 PM). Inverter-based generation is 96 MW.

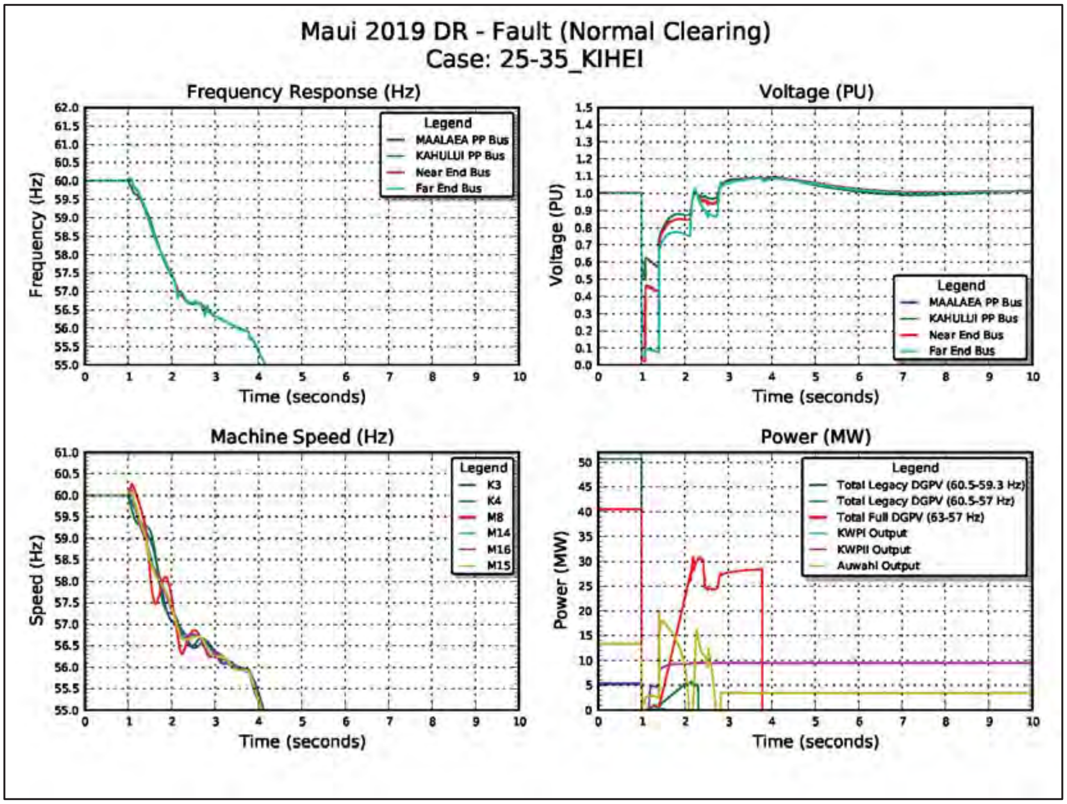

Figure O-255. System Performance for Normally Cleared Fault

Figure O-255 shows the system performance for a normally cleared fault at the Kihei end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 96 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

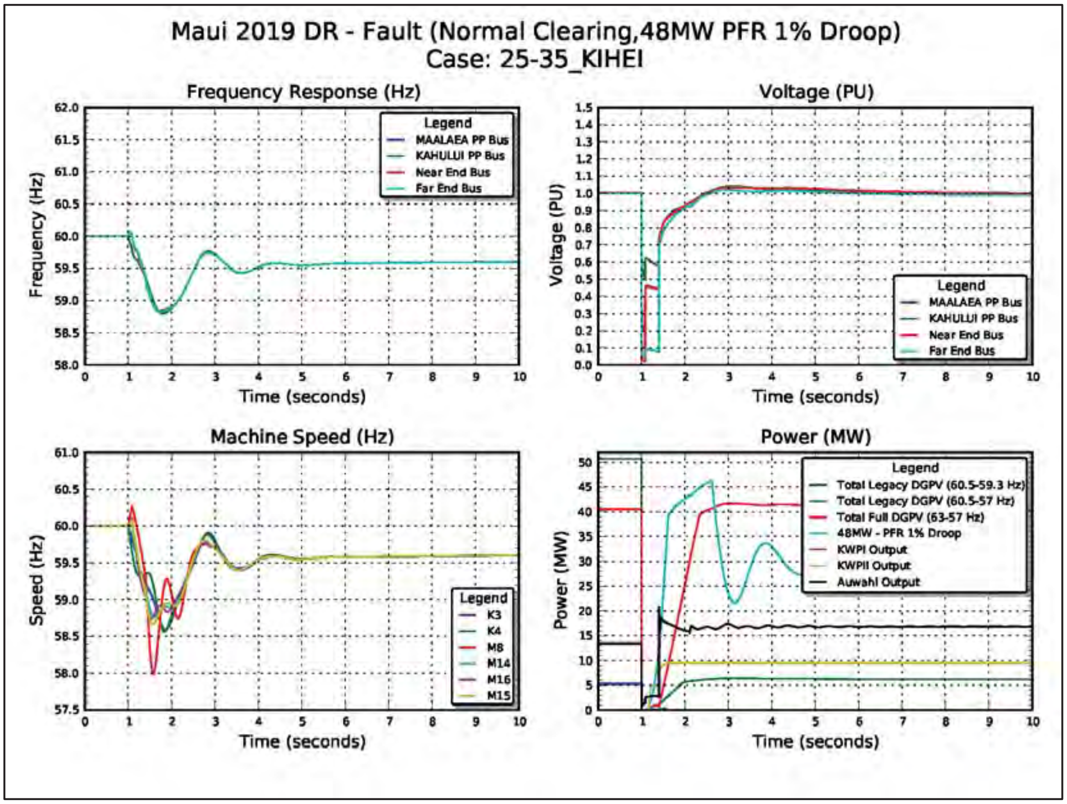

Figure O-256. Normally Cleared Fault Sensitivity 48 MW PFR

Figure O-256 shows system performance with the addition of 48 MW PFR at 1% droop response. For the purpose of this analysis, a 48 MW BESS was located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 48 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2019 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 48MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Stable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Stable	Stable	Stable
	Kula AG	Stable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Stable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Stable	Stable	Stable
	Kula AG	Stable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Stable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Stable	Stable	Stable
	Pukalani	Stable	Stable	Stable

Table O-108. Summary of Results Fault Analysis

Table O-108 shows the results of the 69 kV fault analysis with 48 MW PFR. The Maʻalaea-Waiinu and Maʻalaea–Puʻunene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Wed 8/5/2020 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46			
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					70		
-KWP	30	0				19		
-Auwahi	21	0				19		
-KWPII	21	0				19		
-New Wind 1	30	0						
-New Wind 2	30	0				7		
-New Wind 3	30	0				7		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	6.74	0				6		
DGPV	121	0				92		
Total System MVA						129		
Total Kinetic Energy						335		
Total Load						192		
Total Thermal Generation						24		
Total Renewable Generation						168		
Total Generation						192		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						42		
Total Down Regulation						6		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		4.8
	60.5Hz Capacity			69.5		60.5Hz Output		45.8

Table O-109. Unit Commitment and Dispatch 2020 QV Analysis

Table O-109 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Wed 8/5/2020 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	2.6	1.5	2.6
Maalaea 15	2.9	0.0	3.3	-0.4	3.3
Maalaea 16	4.1	0.0	4.3	-0.2	4.3
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0			
Sync Condenser 1	30.0	-30	8.3	21.7	38.3
Sync Condenser 1 - 23 kV	16.0	-16.0	3.5	12.5	19.5
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.5	13.0	1.7
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0			
-New Wind 2	9.9	0.0			
-New Wind 3	9.9	0.0			
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			24.9		
Total Renewable MVAR Generation			1.5		
Total Cap Bank MVAR			53.3		
Charging MVAR			5.6		
Total MVAR Supply			85.4		
Total MVAR Load			59.3		
Total MVAR Losses			23.9		
Excess MVAR Generation			2.1		
Total MVAR Supply Capability				78	
Total MVAR Absorb Capability					70.9

Table O-110. MVAR Capability 2020 QV Analysis

Table O-110 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu
114	Wailea-Kihei 69 kV

Table O-111. N-1 Contingencies 2020 QV Analysis

Table O-111 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

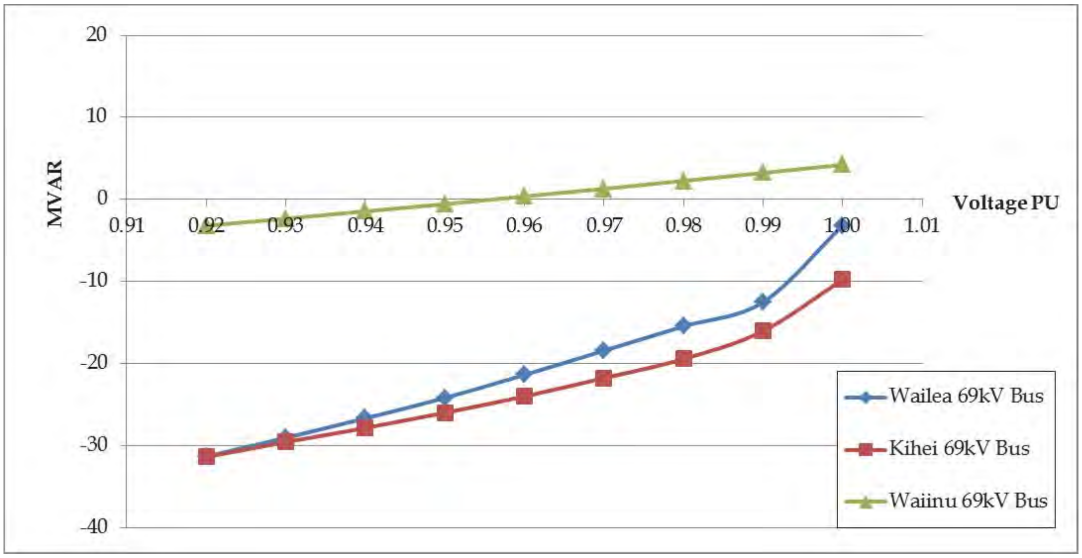

Figure O-257. QV Curves 2020

Figure O-257 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	114	-3	114	-13	114	-15	114	-18	114	-21	114	-24	114	-27	114	-29	114	-31
35	Kihei 69 kV Bus	102	-10	102	-16	102	-19	102	-22	102	-24	102	-26	102	-28	102	-30	102	-31
636	Waiinu 69 kV Bus	104	4	104	3	104	2	104	1	104	0	104	-1	104	-1	104	-2	104	-3

Table O-112. Summary of Results 2020 QV Analysis

Table O-112 shows the results of the QV analysis for 2020. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

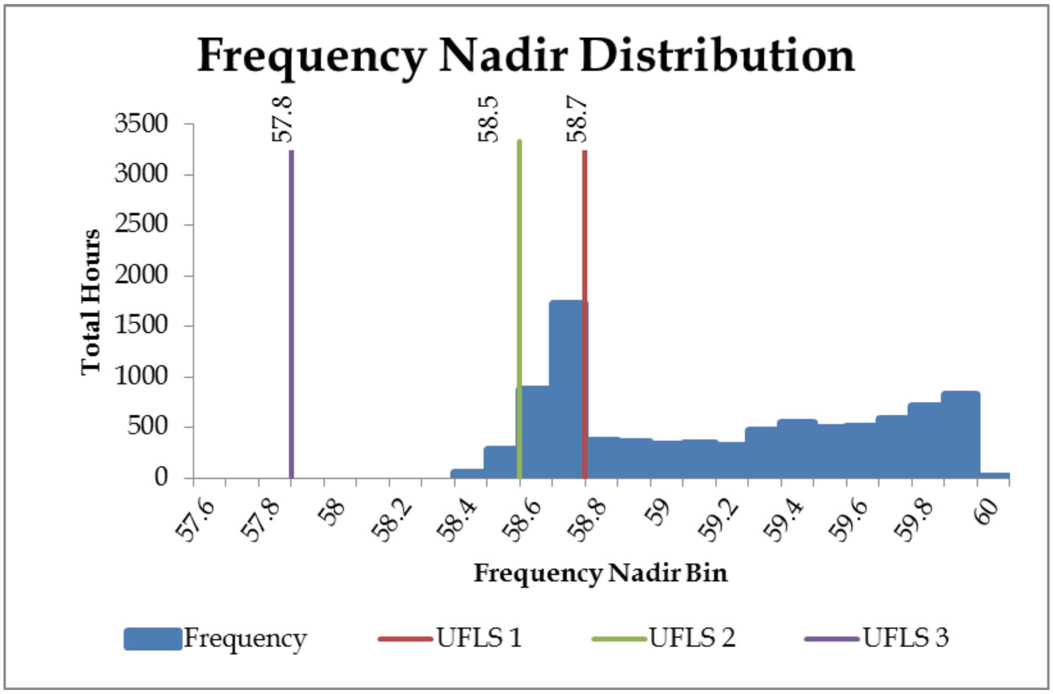

Figure O-258. Frequency Nadir Histogram for 2020

Figure O-258 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 284 hours was 12:00 PM on Thursday, November 26. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 49 hours was 3:00 AM on Thursday, November 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

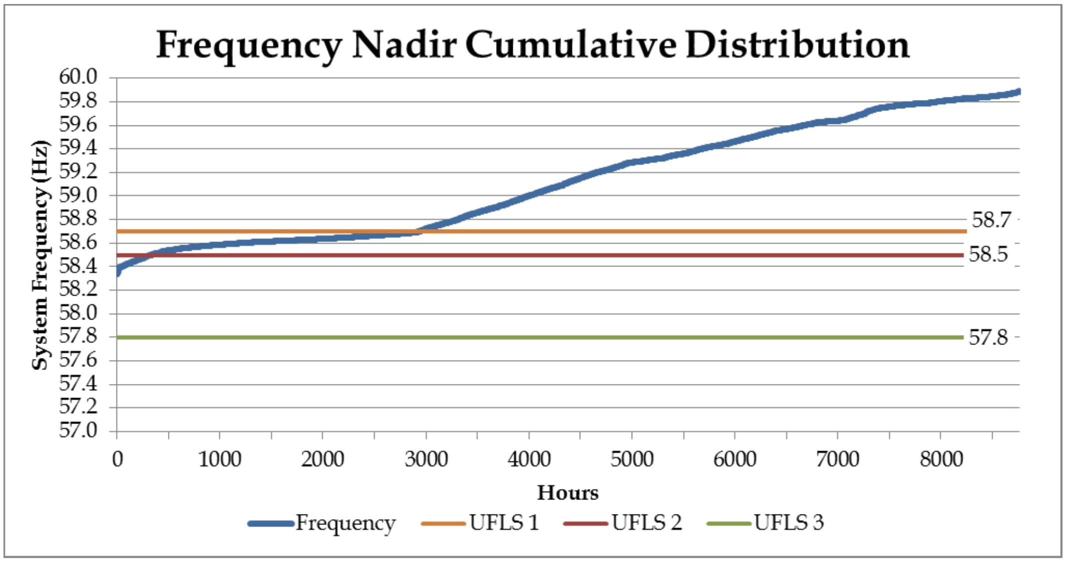

Figure O-259. Frequency Nadir Duration Curve 2020

Figure O-259 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 309 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Thu 11/26/2020 Hour 12			DR - KWP I Trip Boundary Thu 11/26/2020 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88						
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46	7.4	5.6	4.4	7.4	5.6	4.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	72					81			74		
-KWP	30	0				29			30		
-Auwahi	21	0									
-KWPII	21	0				21			21		
-New Wind 1	30	0				10			8		
-New Wind 2	30	0				11			8		
-New Wind 3	30	0				11			8		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
Station PV	6.74	0				6			0%		
DGPV	121	0				60			0%		
Total System MVA							134			134	
Total Kinetic Energy							292			292	
Total Load							177			102	
Total Thermal Generation							28			28	
Total Renewable Generation							148			74	
Total Generation							176			102	
Excess Generation							-1			0	
Regulation Requirement							0			0	
Total Up Regulation							39			39	
Total Down Regulation							10			10	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		3.2	59.3Hz Output		
		60.5Hz Capacity		69.5		60.5Hz Output		30.6	60.5Hz Output		

Table O-113. Unit Commitment and Dispatch 2020

Table O-113 shows the unit commitment and dispatch for the typical hour (11/26/20, 12:00 PM) and boundary hour (11/26/20, 3:00 AM).

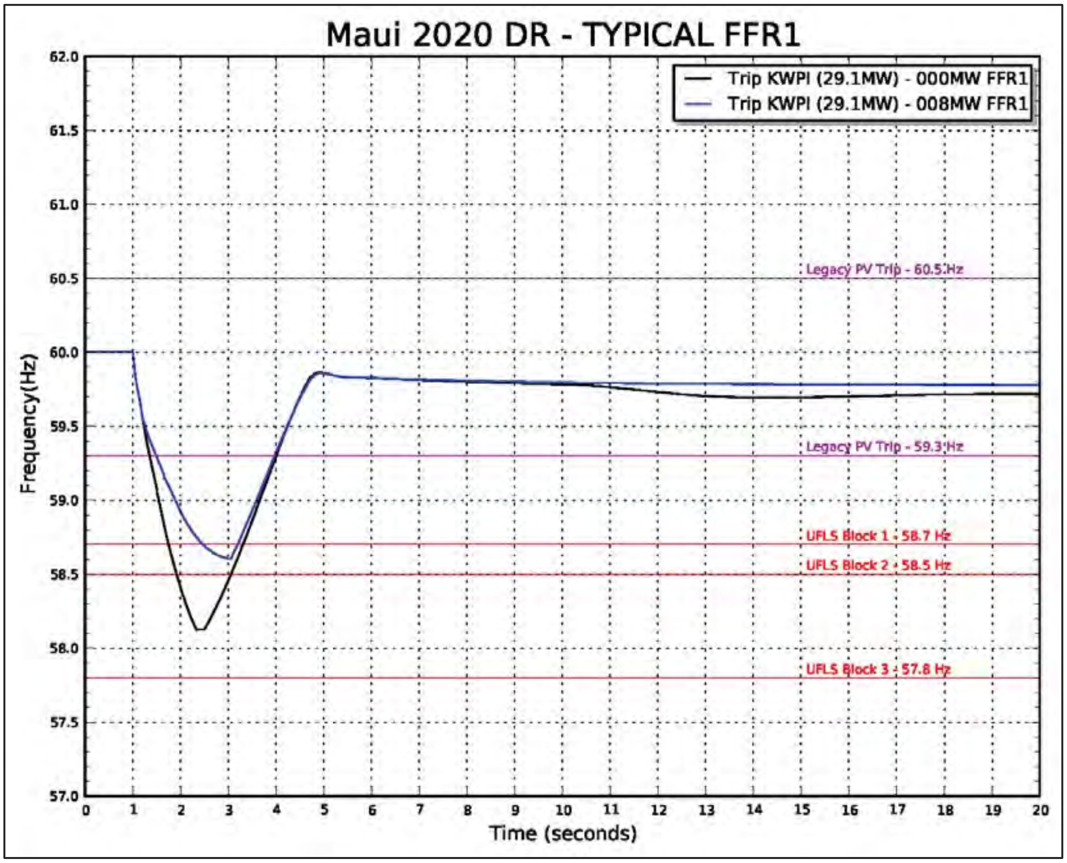

Figure O-260. Frequency Response Profile for FFR1 Typical Hour

Figure O-260 shows the frequency response profile for a KWP 1 trip at 29.1 MW for a typical hour. System kinetic energy is 292 MW-sec and the capacity of legacy PV that will disconnect from the system is 3.2 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

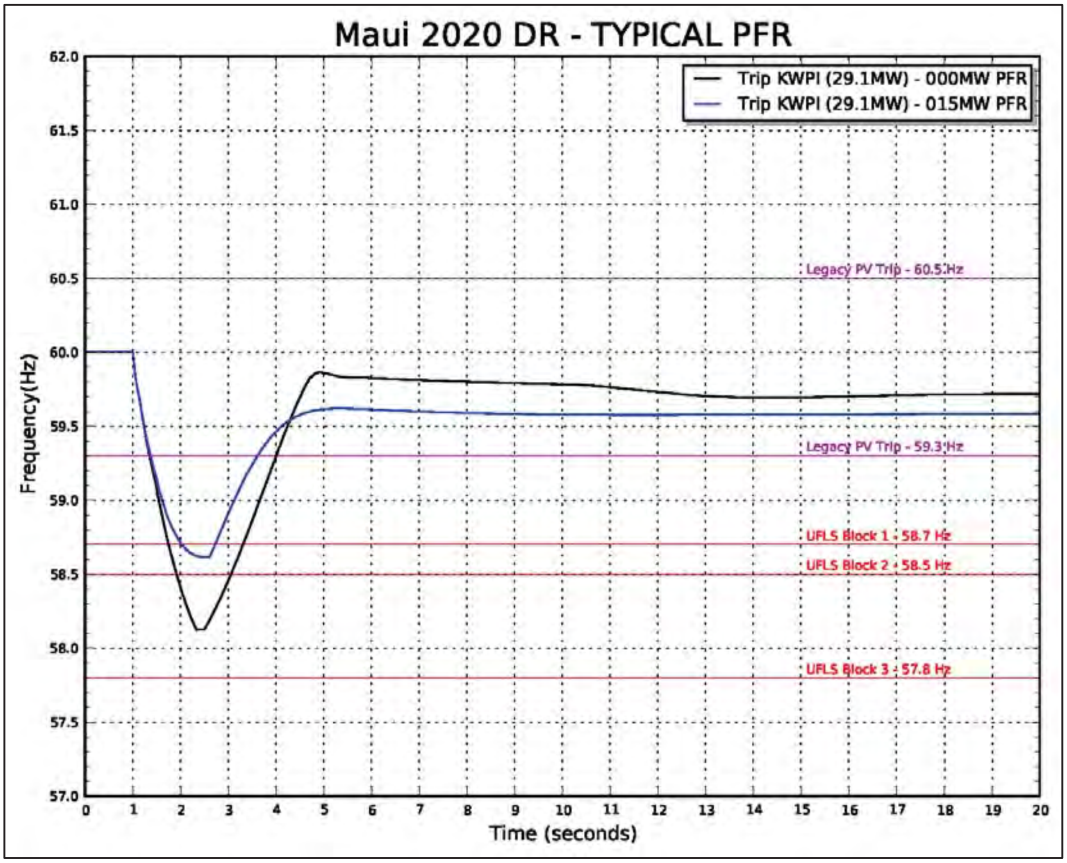

Figure O-261. Frequency Response Profile for PFR Typical Hour

Figure O-261 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

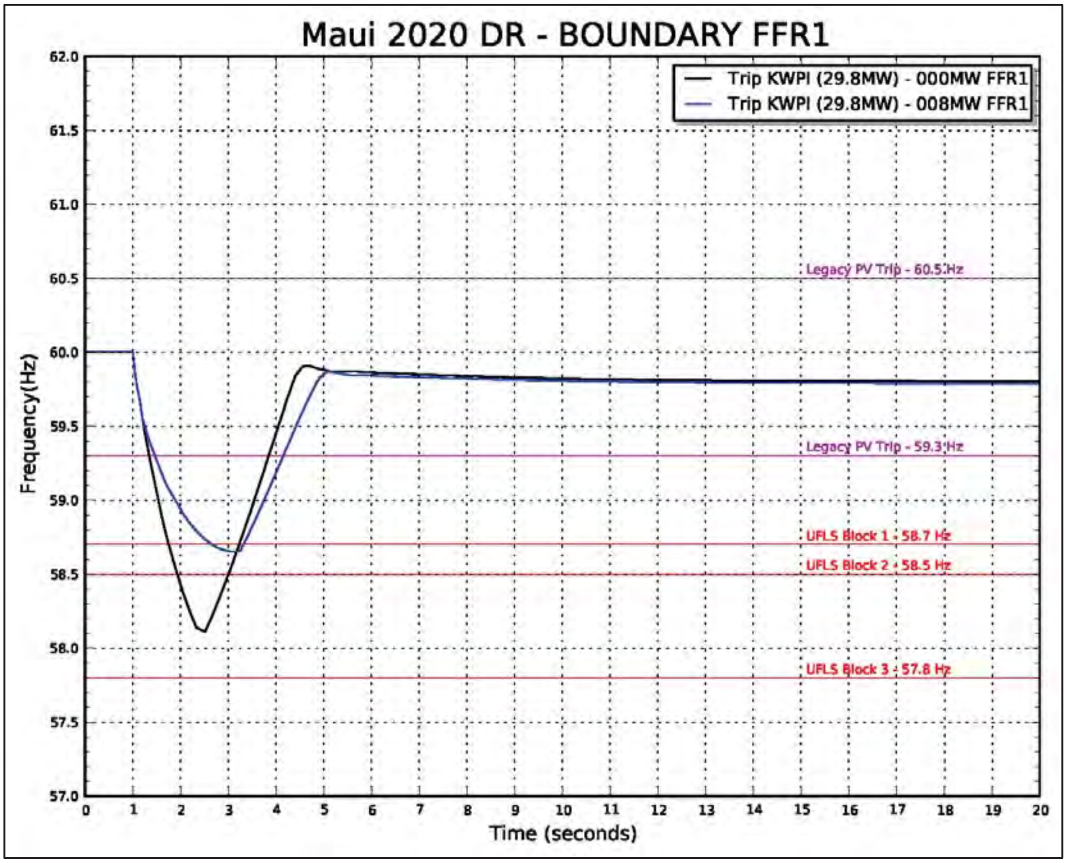

Figure O-262. Frequency Response Profile for FFR1 Boundary Hour

Figure O-262 shows the frequency response profile for a KWP 1 trip at 29.8 MW for a boundary hour. System kinetic energy is 292 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

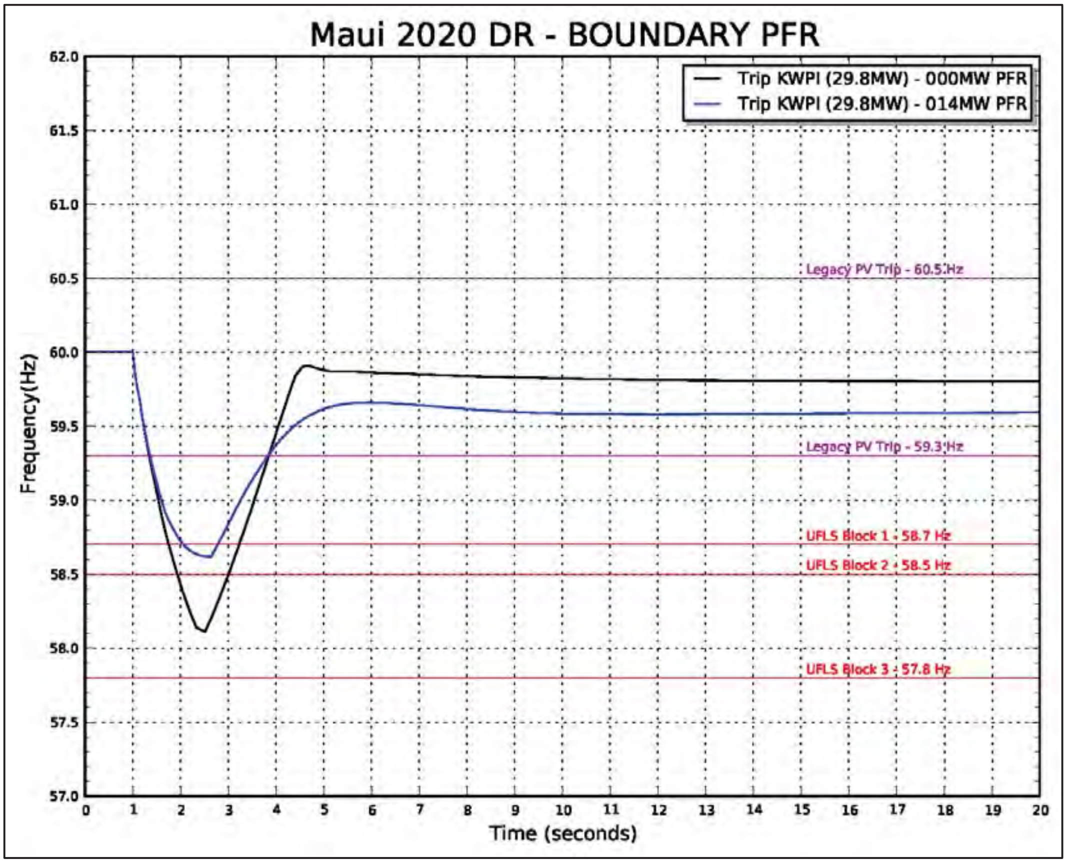

Figure O-263. Frequency Response Profile for PFR Boundary Hour

Figure O-263 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Tue 5/12/2020 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58			
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54	11.9	9.3	6.0
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					46		
-KWP	30	0				26		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0						
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	6.74	0				6		
DGPV	121	0				102		
Total System MVA						120		
Total Kinetic Energy						322		
Total Load						180		
Total Thermal Generation						22		
Total Renewable Generation						155		
Total Generation						177		
Excess Generation						-3		
Regulation Requirement						0		
Total Up Regulation						36		
Total Down Regulation						7		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.3
	60.5Hz Capacity			69.5		60.5Hz Output		51.4

Table O-114. Unit Commitment and Dispatch Fault Analysis 2020

Table O-114 shows the unit commitment and dispatch for the 69 kV fault analysis (5/12/20, 1:00 PM). Inverter-based generation is 102 MW.

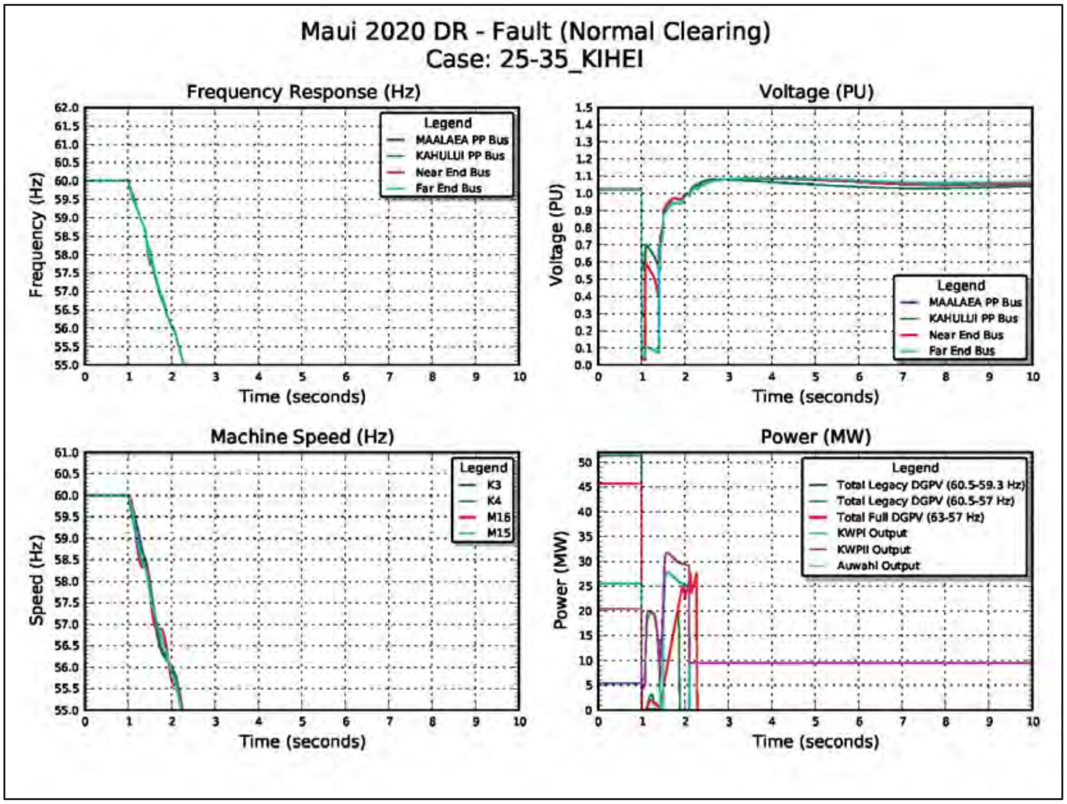

Figure O-264. System Performance for Normally Cleared Fault

Figure O-264 shows the system performance for a normally cleared fault at the Kihei end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 102 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

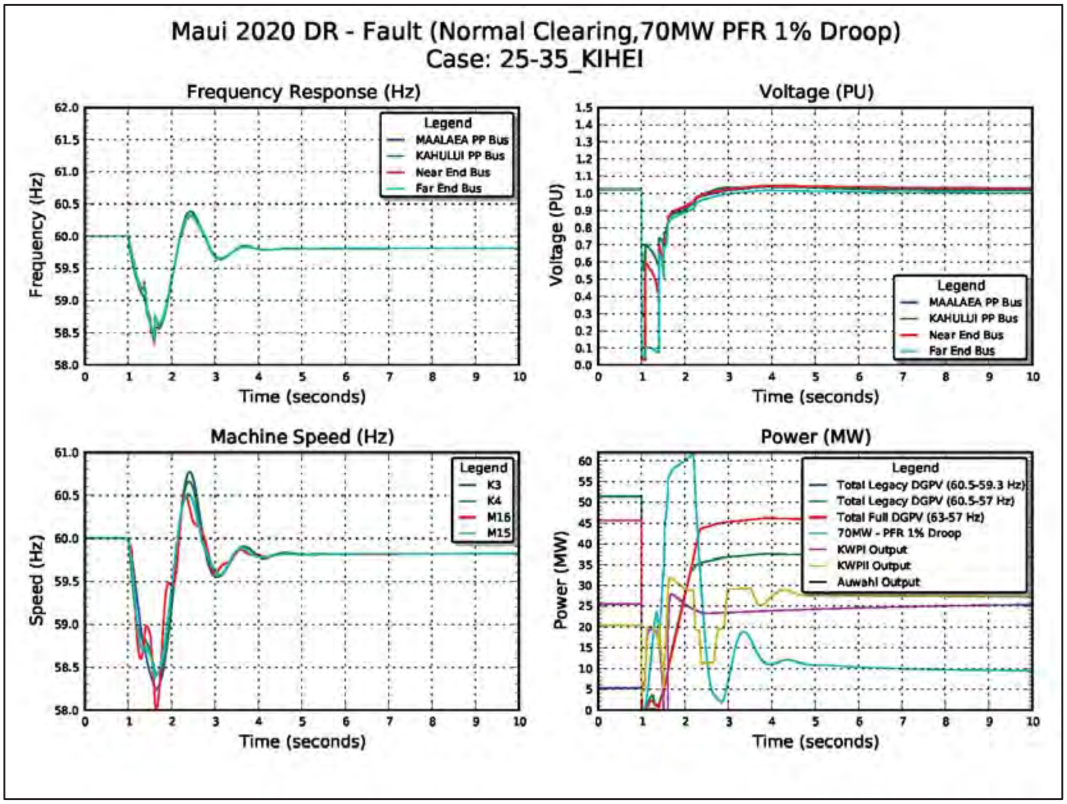

Figure O-265. Normally Cleared Fault Sensitivity 70 MW PFR

Figure O-265 s shows system performance with the addition of 70 MW PFR at 1% droop response. For the purpose of this analysis, a 70 MW BESS was located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 70 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2020 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 70MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Unstable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Unstable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Unstable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR1	Unstable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR2	Unstable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR3	Unstable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-115. Summary of Results Fault Analysis 2020

Table O-115 shows the results of the 69 kV fault analysis with 70 MW PFR. The Lahaina-Lahaina Luna, Maʻalaea-Waiinu and Maʻalaea–Puʻunene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Thu 8/19/2021 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	11.9	9.3	6.0
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54			
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	162					103		
-KWP	30	0				28		
-Auwahi	21	0				16		
-KWPII	21	0				15		
-New Wind 1	30	0				14		
-New Wind 2	30	0				15		
-New Wind 3	30	0				15		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	8	0				5		
DGPV	128	0				63		
Total System MVA						120		
Total Kinetic Energy						326		
Total Load						193		
Total Thermal Generation						22		
Total Renewable Generation						172		
Total Generation						193		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						36		
Total Down Regulation						7		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		3.2
	60.5Hz Capacity			69.5		60.5Hz Output		30.6

Table O-116. Unit Commitment and Dispatch 2021 QV Analysis

Table O-116 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit Commitment Order	Unit Ratings		DR - QV MVAR Capability Thu 8/19/2021 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	2.6	1.5	2.6
Maalaea 15	2.9	0.0	1.8	1.1	1.8
Maalaea 16	4.1	0.0			
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Sync Condenser 1	30.0	-30	15.8	14.2	45.8
Sync Condenser 1 - 23 k	16.0	-16.0	5.3	10.7	21.3
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.2	13.3	1.5
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.5	9.4	0.5
-New Wind 2	9.9	0.0	0.4	9.4	0.4
-New Wind 3	9.9	0.0	0.0	9.9	0.0
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			28.4		
Total Renewable MVAR Generation			2.1		
Total Cap Bank MVAR			53.0		
Charging MVAR			5.6		
Total MVAR Supply			89.2		
Total MVAR Load			59.8		
Total MVAR Losses			29.3		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				100	
Total MVAR Absorb Capability					74.4

Table O-117. MVAR Capability 2021 QV Analysis

Table O-117 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu
113	Wailea-Auwahi 69 kV
114	Wailea-Kihei 69 kV

Table O-118. N-1 Contingencies 2021 QV Analysis

Table O-118 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

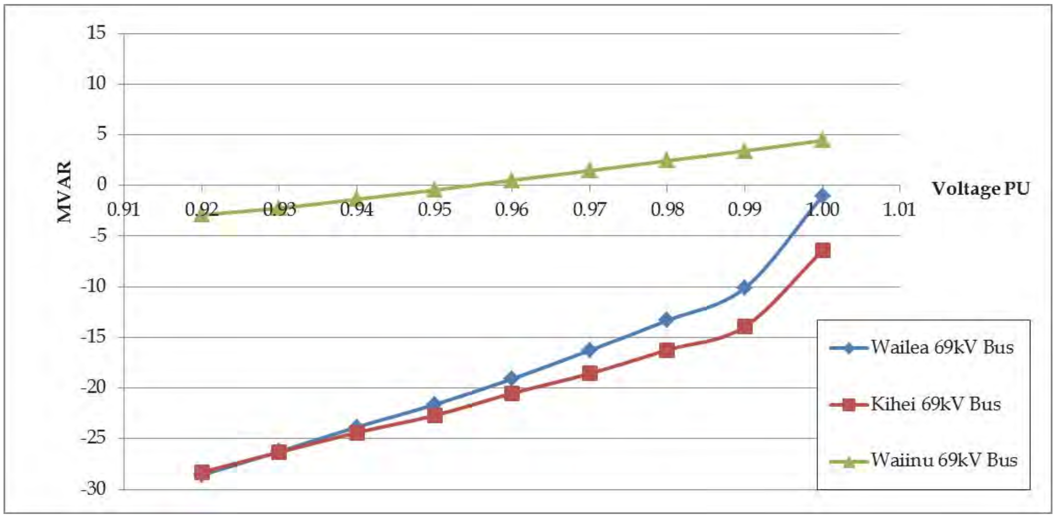

Figure O-266. QV Curves 2021

Figure O-266 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	114	-1	113	-10	114	-13	114	-16	114	-19	114	-22	114	-24	114	-26	114	-29
35	Kihei 69 kV Bus	102	-6	102	-14	102	-16	102	-19	102	-21	102	-23	102	-24	102	-26	102	-28
636	Waiinu 69 kV Bus	104	4	104	3	104	2	104	1	104	1	104	0	104	-1	104	-2	104	-3

Table O-119. Summary of Results 2021 QV Analysis

Table O-119 shows the results of the QV analysis for 2019. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

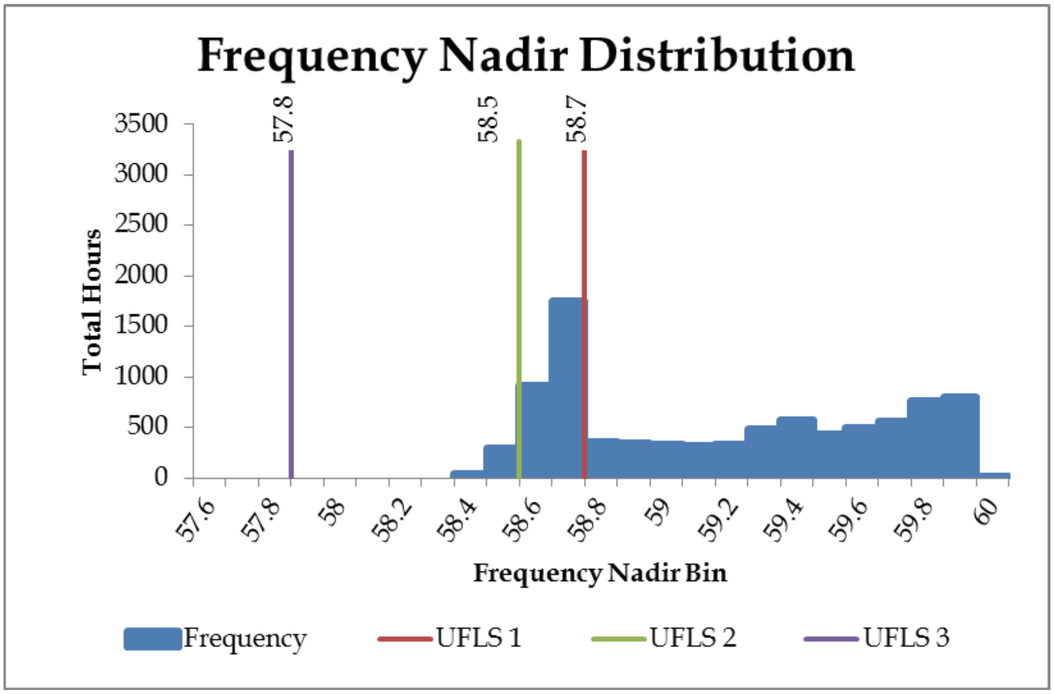

Figure O-267. Frequency Nadir Histogram for 2021

Figure O-267 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 288 hours was 1:00 PM on Thursday, November 25. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 37 hours was 3:00 AM on Thursday, November 25. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

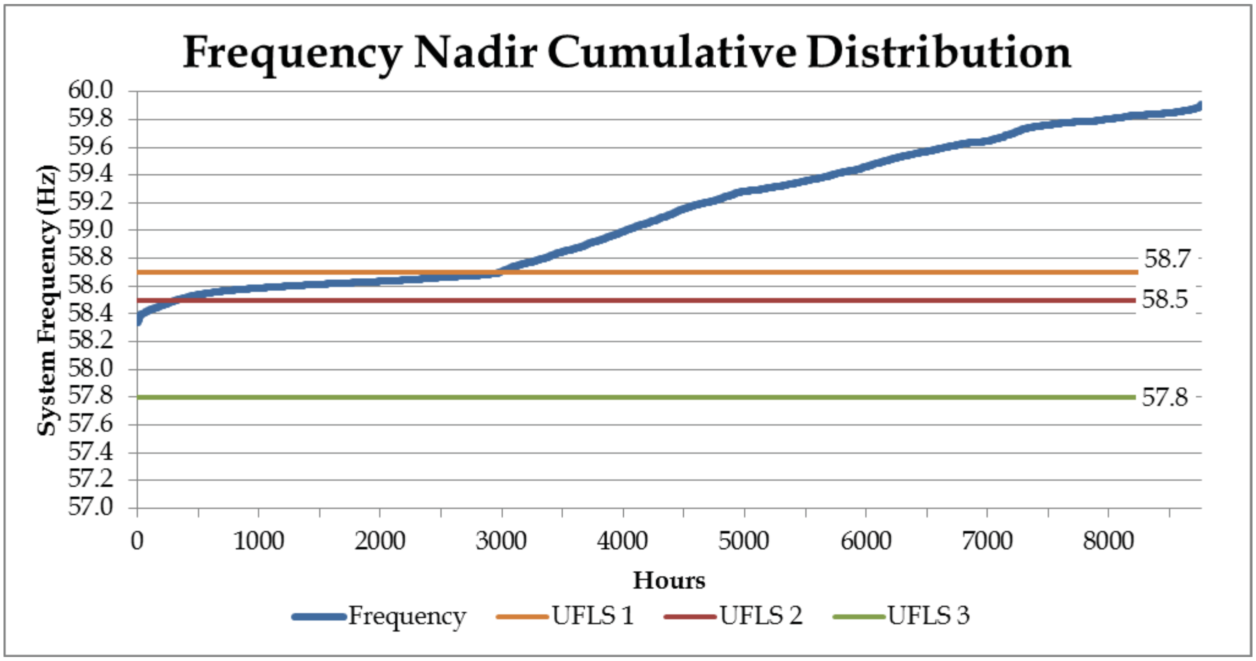

Figure O-268. Frequency Nadir Duration Curve 2021

Figure O-268 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 325 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Thu 11/25/2021 Hour 13			DR - KWP I Trip Boundary Thu 11/25/2021 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88						
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46	7.4	5.6	4.4	7.4	5.6	4.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					68			74		
-KWP	30	0				30			30		
-Auwahi	21	0									
-KWPII	21	0				21			21		
-New Wind 1	30	0				6			8		
-New Wind 2	30	0				6			8		
-New Wind 3	30	0				6			8		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
Station PV	8	0				5					
DGPV	128	0				74					
Total System MVA						134			134		
Total Kinetic Energy						292			292		
Total Load						177			103		
Total Thermal Generation						28			28		
Total Renewable Generation						147			74		
Total Generation						175			102		
Excess Generation						-2			-1		
Regulation Requirement						0			0		
Total Up Regulation						39			39		
Total Down Regulation						10			10		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		3.2	59.3Hz Output		
	60.5Hz Capacity			69.5		60.5Hz Output		30.6	60.5Hz Output		

Table O-120. Unit Commitment and Dispatch 2021

Table O-120 shows the unit commitment and dispatch for the typical hour (11/25/21, 1:00 PM) and boundary hour (11/25/01, 3:00 AM).

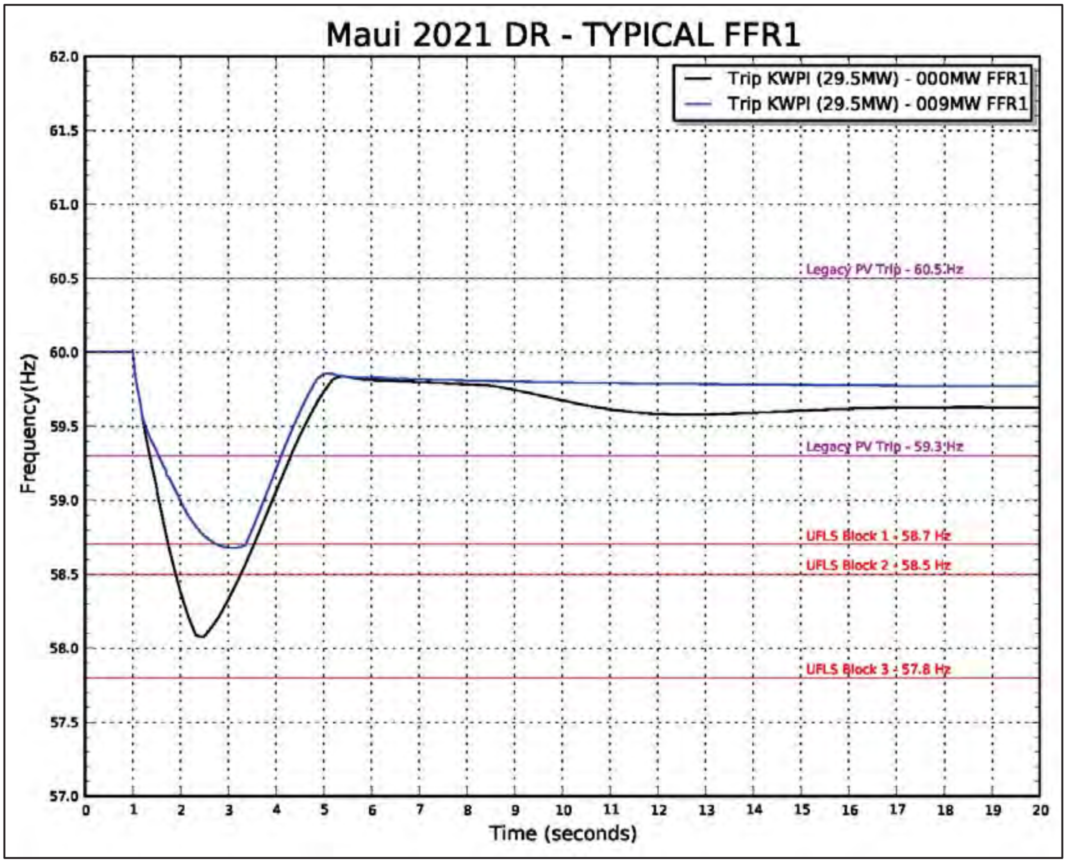

Figure O-269. Frequency Response Profile for FFR1 Typical Hour

Figure O-269 shows the frequency response profile for a KWP 1 trip at 29.5 MW for a typical hour. System kinetic energy is 292 MW-sec and the capacity of legacy PV that will disconnect from the system is 3.2 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

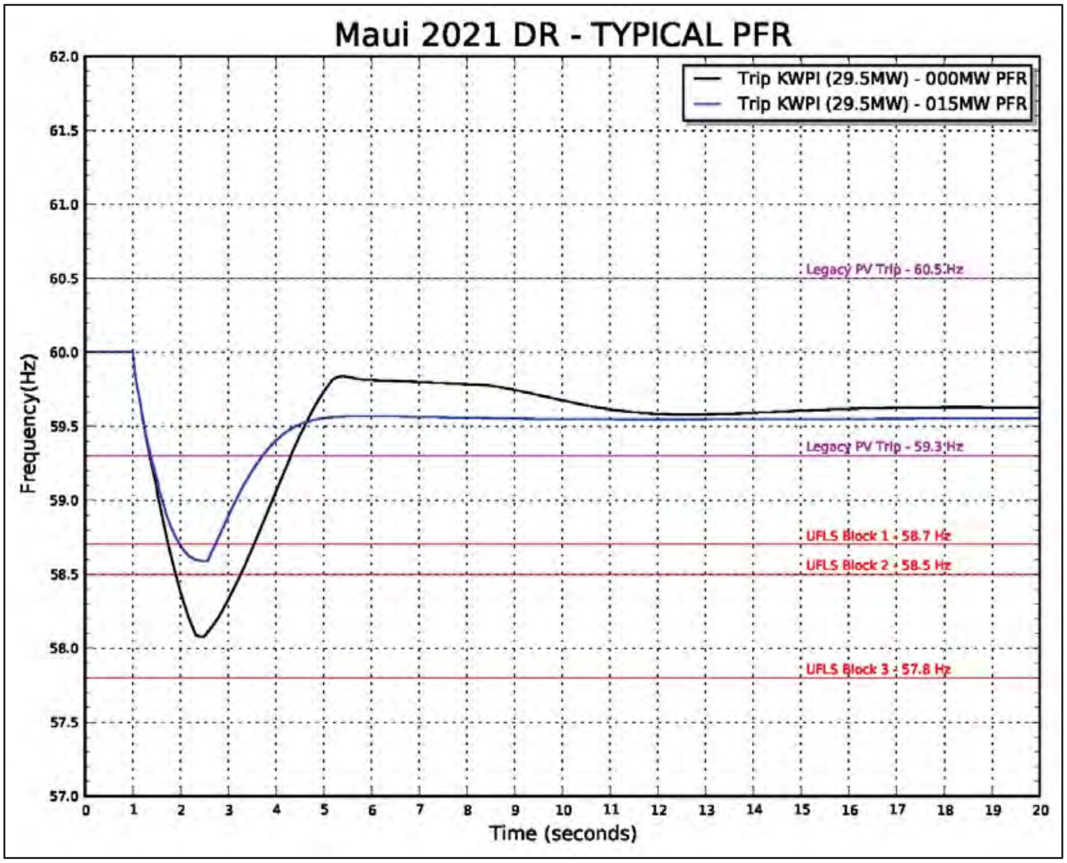

Figure O-270. Frequency Response Profile for PFR Typical Hour

Figure O-270 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

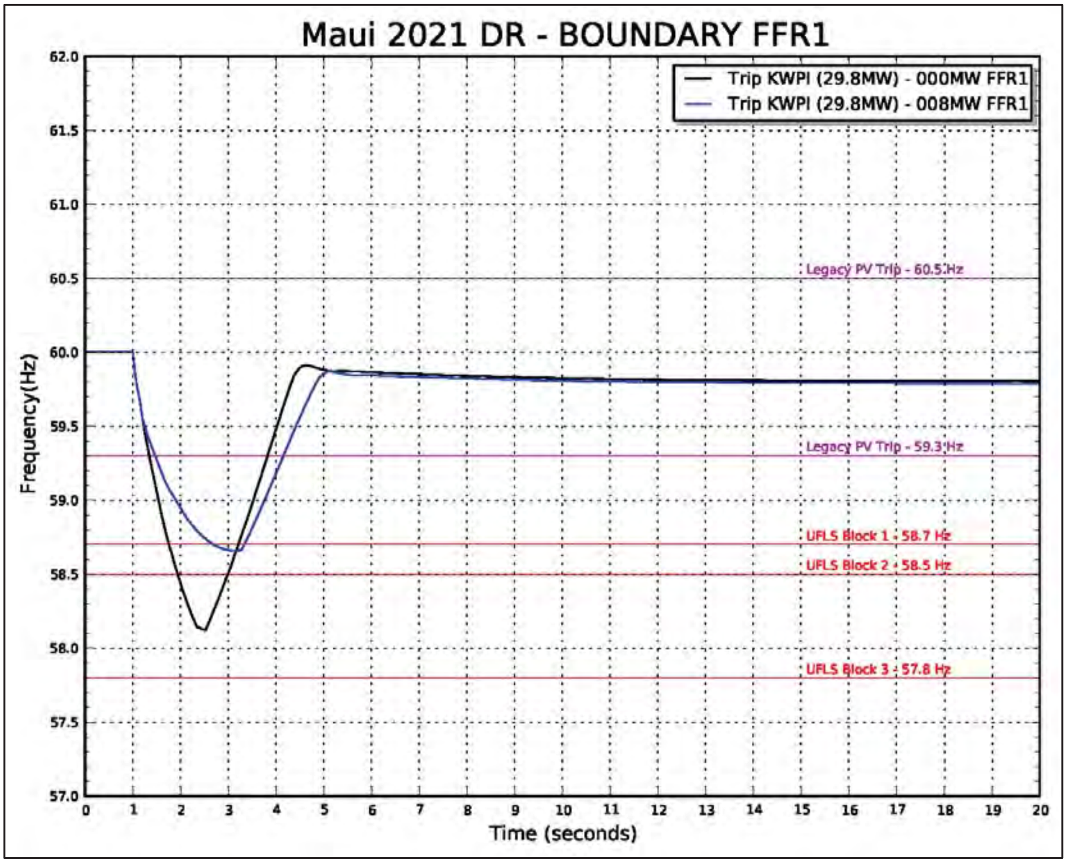

Figure O-271. Frequency Response Profile for FFR1 Boundary Hour

Figure O-271 shows the frequency response profile for a KWP 1 trip at 29.8 MW for a boundary hour. System kinetic energy is 292 MW-sec. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

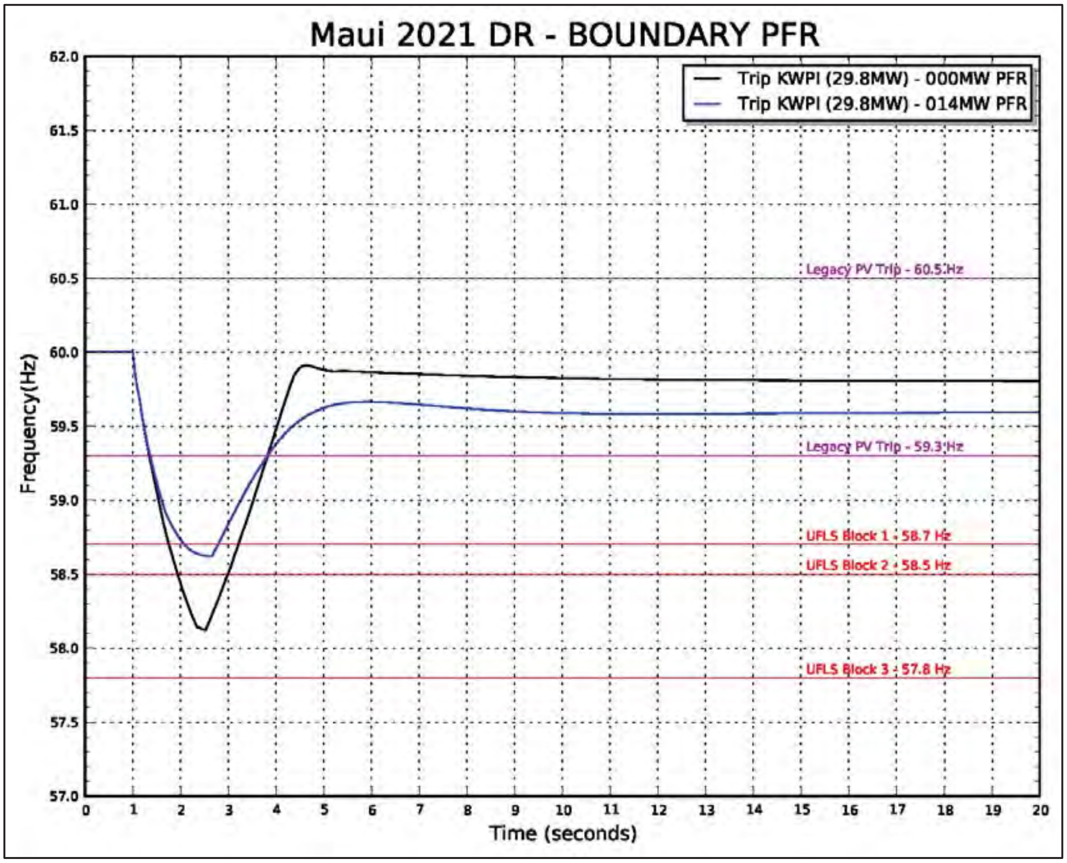

Figure O-272. Frequency Response Profile for PFR Boundary Hour

Figure O-272 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Sat 5/15/2021 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	6.1	5.4	3.1
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	9.4	11.8	3.4
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54			
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16	1.9	3.7	0.0
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*	
Total Wind	162					24		
-KWP	30	0						
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				1		
-New Wind 2	30	0				1		
-New Wind 3	30	0				1		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	8	0				6		
DGPV	128	0				108		
Total System MVA							134	
Total Kinetic Energy							358	
Total Load							167	
Total Thermal Generation							30	
Total Renewable Generation							138	
Total Generation							167	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							39	
Total Down Regulation							11	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		5.2
		60.5Hz Capacity		69.5		60.5Hz Output		50.0

Table O-121. Unit Commitment and Dispatch Fault Analysis 2021

Table O-121 shows the unit commitment and dispatch for the 69 kV fault analysis (5/15/21, 12:00 PM). Inverter-based generation is 108 MW.

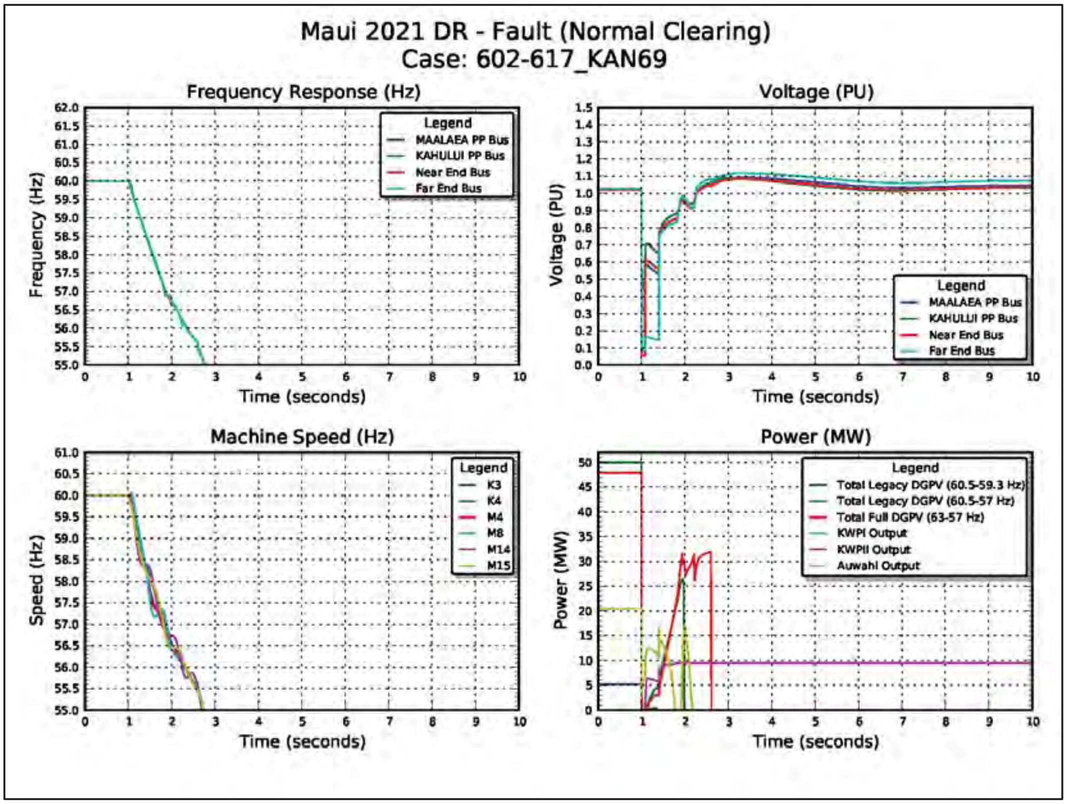

Figure O-273. System Performance for Normally Cleared Fault

Figure O-273 shows the system performance for a normally cleared fault at the Kanaha end of the Kanaha-Pukalani circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 108 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

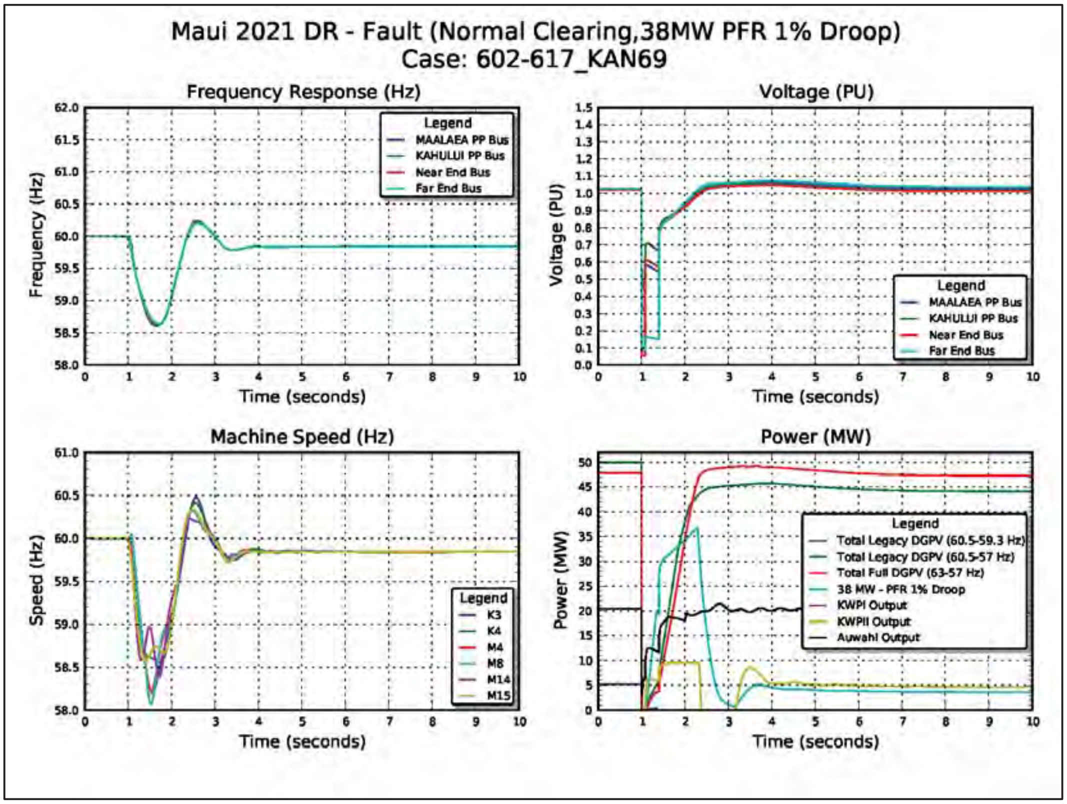

Figure O-274. Normally Cleared Fault Sensitivity 38 MW PFR

Figure O-274 shows system performance with the addition of 38 MW PFR at 1% droop response. For the purpose of this analysis, a 38 MW BESS was located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 38 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2021 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation 38MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR1	Unstable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR2	Unstable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR3	Unstable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-122. Summary of Results Fault Analysis 2021

Table O-122 shows the results of the 69 kV fault analysis with 38 MW of PFR. Only the Ma‘alaea-Waiinu and Ma‘alaea–Pu‘unene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

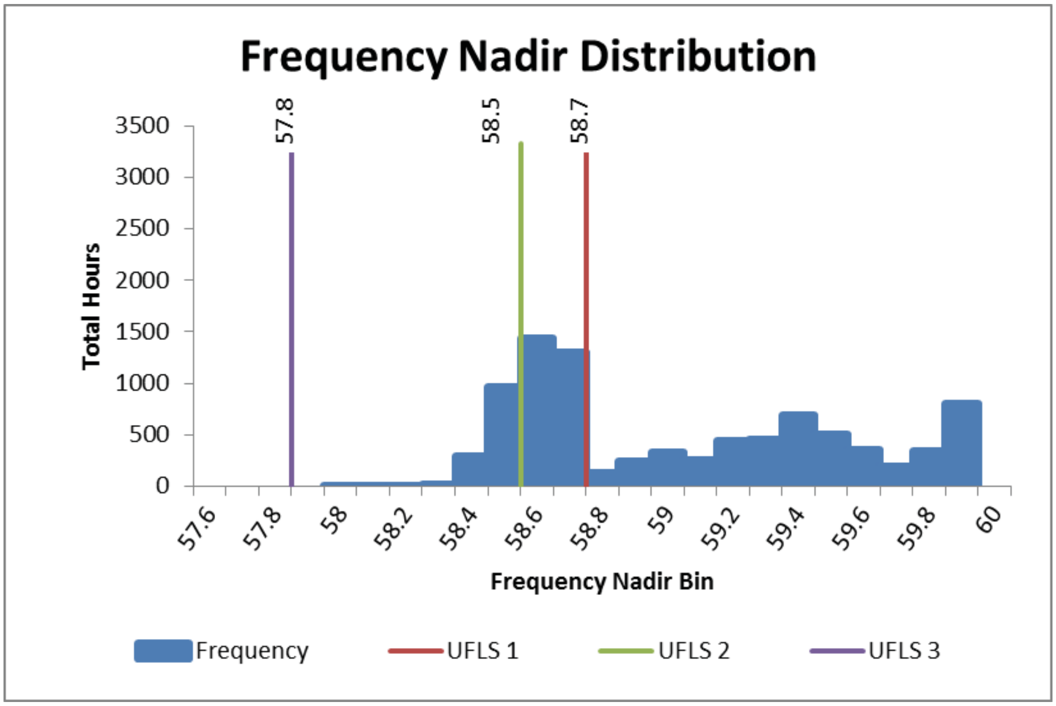

Figure O-275. Frequency Nadir Histogram for 2023

Figure O-275 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 959 hours was 1:00 PM on Monday, April 10. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 24 hours was 1:00 AM on Sunday, July 23. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

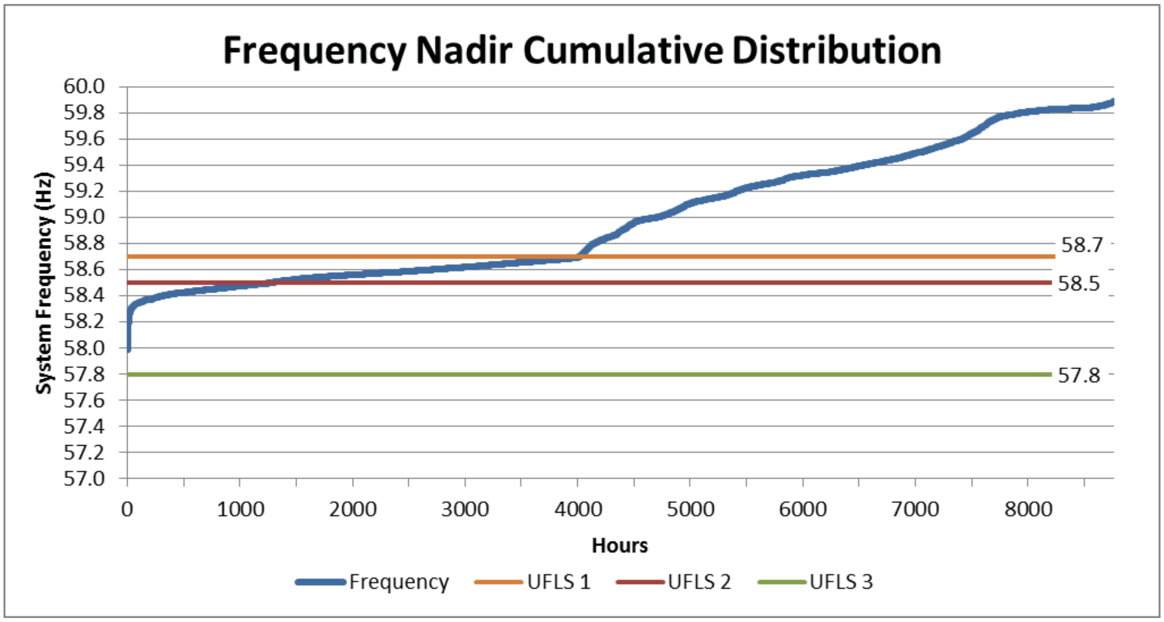

Figure O-276. Frequency Nadir Duration Curve 2023

Figure O-276 shows the frequency nadir duration curve for the resource plan in 2023. The system is at risk of exceeding the UFLS requirements of TPL-001 for 1284 hours of the year.

Unit	Unit Ratings					DR - KWP 1 Trip Typical Mon 4/10/2023 Hour 12			DR - KWP 1 Trip Boundary Sun 7/23/2023 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87	8.0	12.0	2.0			
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	0.0	0.0	2.62	6.3	16	*Retired*			*Retired*		
Kahului 2	0.0	0.0	2.62	6.3	16	*Retired*			*Retired*		
Kahului 4	0.0	0.0	1.74	15.6	27	*Retired*			*Retired*		
Kahului 3	0.0	0.0	3.27	13.5	44	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 3	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					93			98		
-KWP	30	0				30			29		
-Auwahi	21	0									
-KWPII	21	0				21			20		
-New Wind 1	30	0				14			16		
-New Wind 2	30	0				14			16		
-New Wind 3	30	0				14			16		
Total Utility PV	80					6			6		
-Utility PV1	20	0				6			6		
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				93			91		
DER Grid Ex	10	0				0			0		
Total System MVA						145			120		
Total Kinetic Energy						316			229		
Total Load						200			196		
Total Thermal Generation						8			0		
Total Renewable Generation						192			195		
Total Generation						200			195		
Excess Generation						0			-1		
Regulation Requirement						0			0		
Total Up Regulation						12			0		
Total Down Regulation						2			0		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		4.5	59.3Hz Output		4.4
	60.5Hz Capacity			69.5		60.5Hz Output		43.8	60.5Hz Output		46.8

Table O-123. Unit Commitment and Dispatch 2023

Table O-123 shows the unit commitment and dispatch for the typical hour (4/10/23, 12:00 PM) and boundary hour (7/23/23, 1:00 PM).

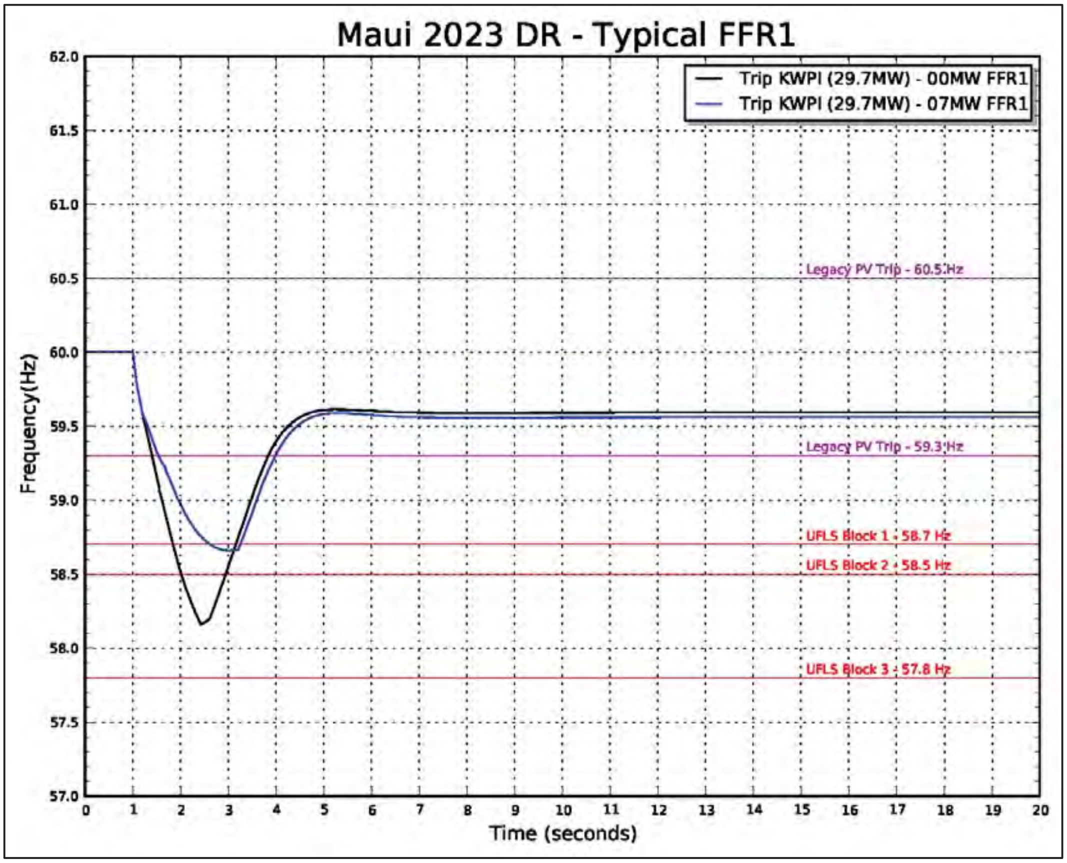

Figure O-277. Frequency Response Profile for FFR1 Typical Hour

Figure O-277 shows the frequency response profile for a KWP 1 trip at 29.7 MW for a typical hour. System kinetic energy is 316 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.5 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7MW.

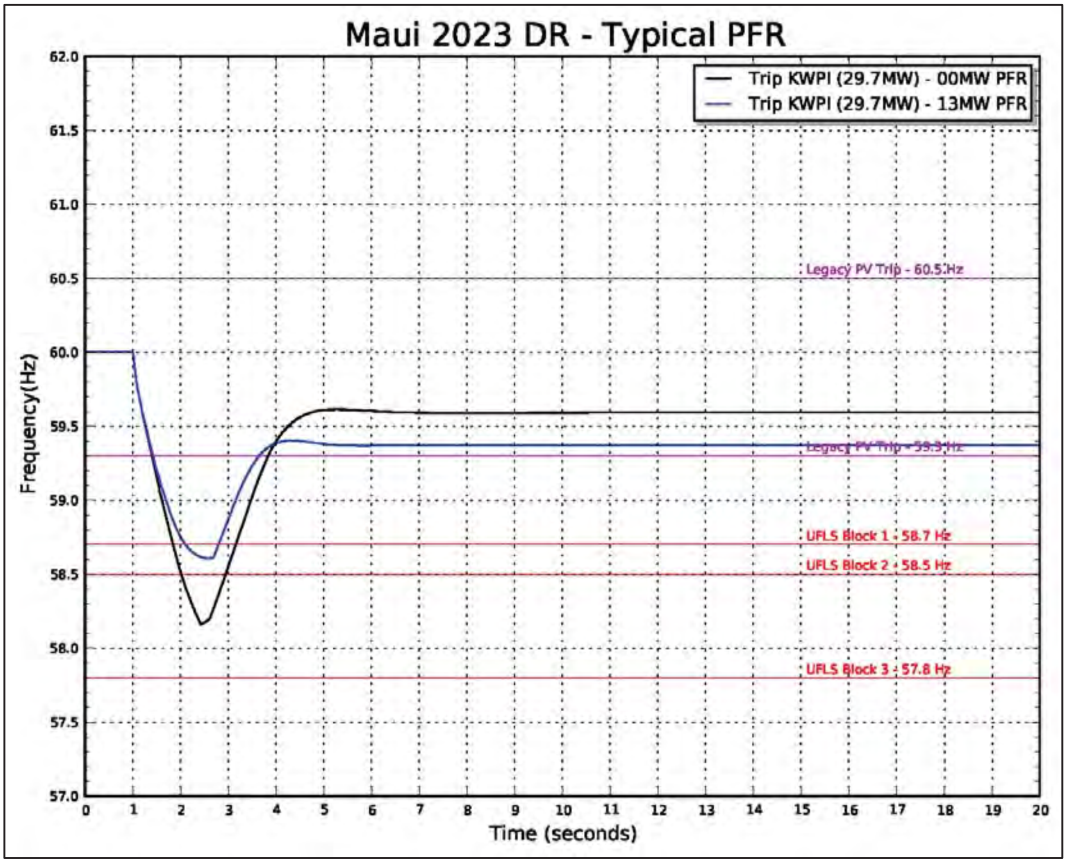

Figure O-278. Frequency Response Profile for PFR Typical Hour

Figure O-278 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 13 MW.

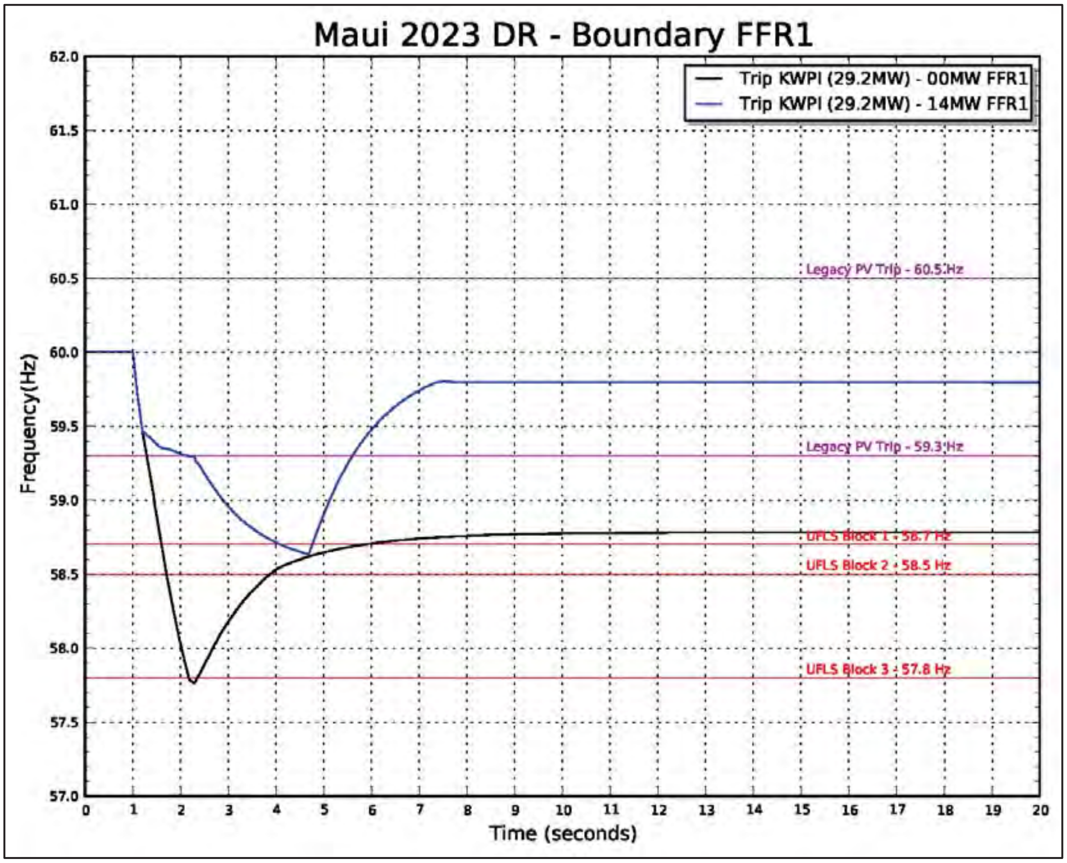

Figure O-279. Frequency Response Profile for FFR1 Boundary Hour

Figure O-279 shows the frequency response profile for a KWP 1 trip at 29.2 MW for a boundary hour. System kinetic energy is 229 MW-sec and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 4.4 MW. With no FFR, the frequency nadir breaches 57.8 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 14 MW.

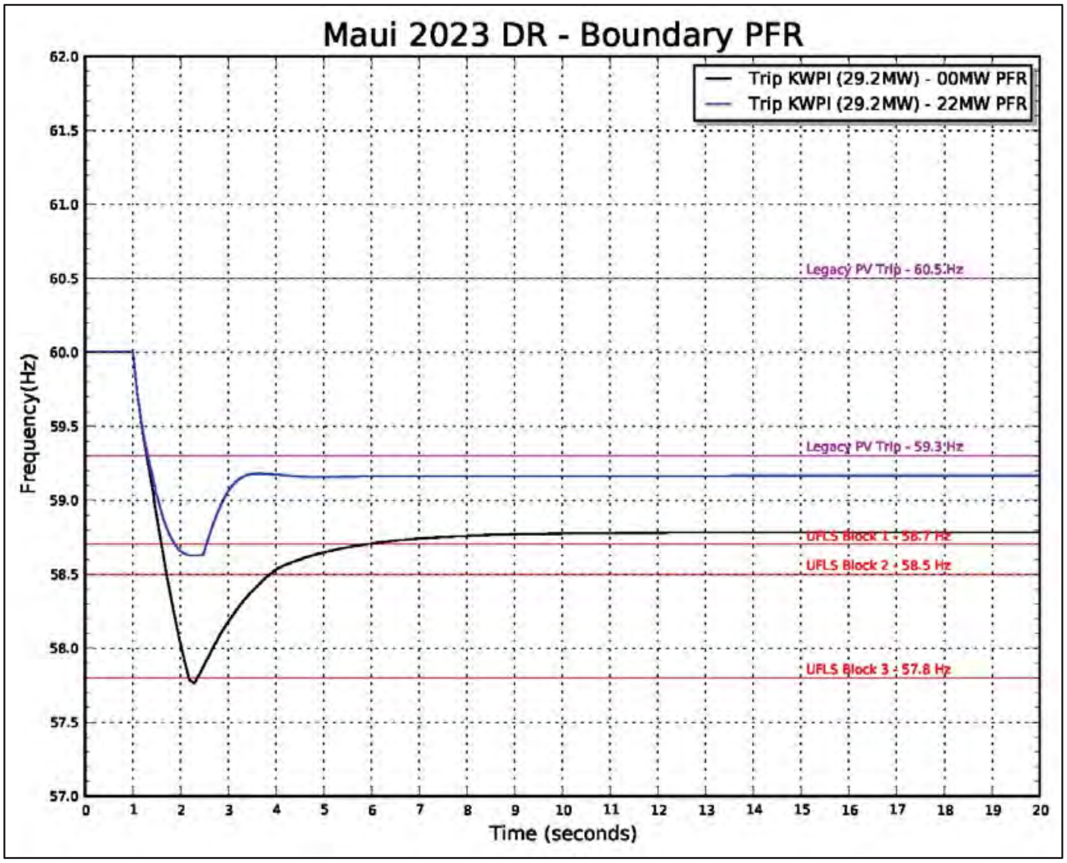

Figure O-280. Frequency Response Profile for PFR Boundary Hour

Figure O-280 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 22 MW.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

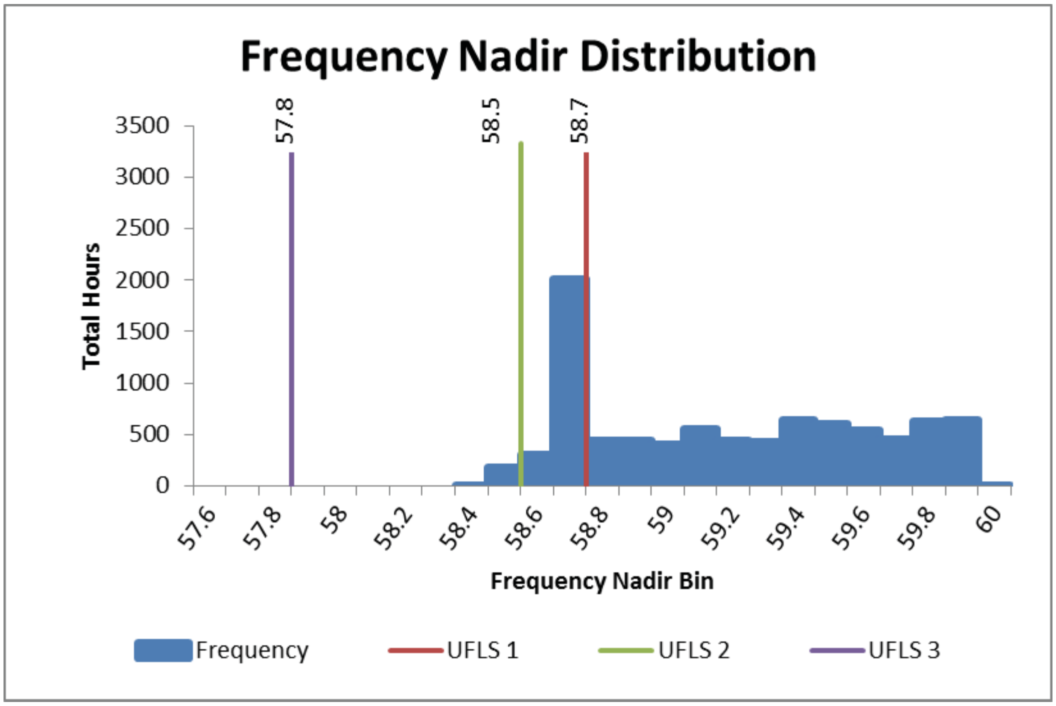

Figure O-281. Frequency Nadir Histogram for 2030

Figure O-281 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 184 hours was 4:00 AM on Tuesday, March 26. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 4 hours was 3:00 AM on Sunday, March 24. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

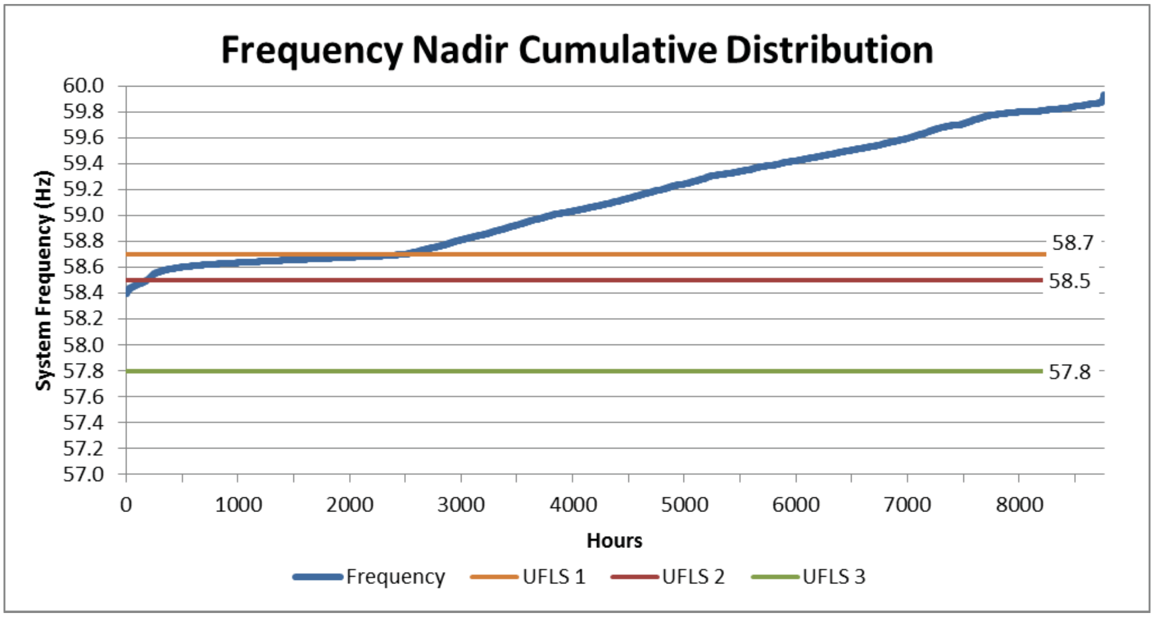

Figure O-282. Frequency Nadir Duration Curve 2030

Figure O-282 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 188 hours of the year.

Unit	Unit Ratings					DR - KWP 1 Trip Typical Tues 3/26/2030 Hour 4			DR - KWP 1 Trip Boundary Sun 3/24/2030 Hour 2		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87						
Geothermal 1	20.0	5.0	3.48	25.0	87	5.6			5.6		
Geothermal 2	20.0	5.0	3.48	25.0	87	5.6			5.6		
4Hr LS BESS	20.0	0.0			0	20.0					
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	0.0	0.0	2.62	6.3	16	*Retired*			*Retired*		
Kahului 2	0.0	0.0	2.62	6.3	16	*Retired*			*Retired*		
Kahului 4	0.0	0.0	1.74	15.6	27	*Retired*			*Retired*		
Kahului 3	0.0	0.0	3.27	13.5	44	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 3	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sml Sync Condenser 1	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					64			94		
-KWP	30	0				29			29		
-Auwahi	21	0									
-KWPII	21	0				19			21		
-New Wind 1	30	0				5			15		
-New Wind 2	30	0				5			15		
-New Wind 3	30	0				5			15		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				0			0		
DER Grid Ex	10	0				6			0		
Total System MVA						170			170		
Total Kinetic Energy						403			403		
Total Load						102			105		
Total Thermal Generation						31			11		
Total Renewable Generation						70			94		
Total Generation						102			105		
Excess Generation						0			0		
Regulation Requirement[1]						0			0		
Total Up Regulation						0			0		
Total Down Regulation						0			0		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-124. Unit Commitment and Dispatch 2030

Table O-124 shows the unit commitment and dispatch for the typical hour (3/26/30, 4:00 AM) and boundary hour (3/24/30, 2:00 AM).

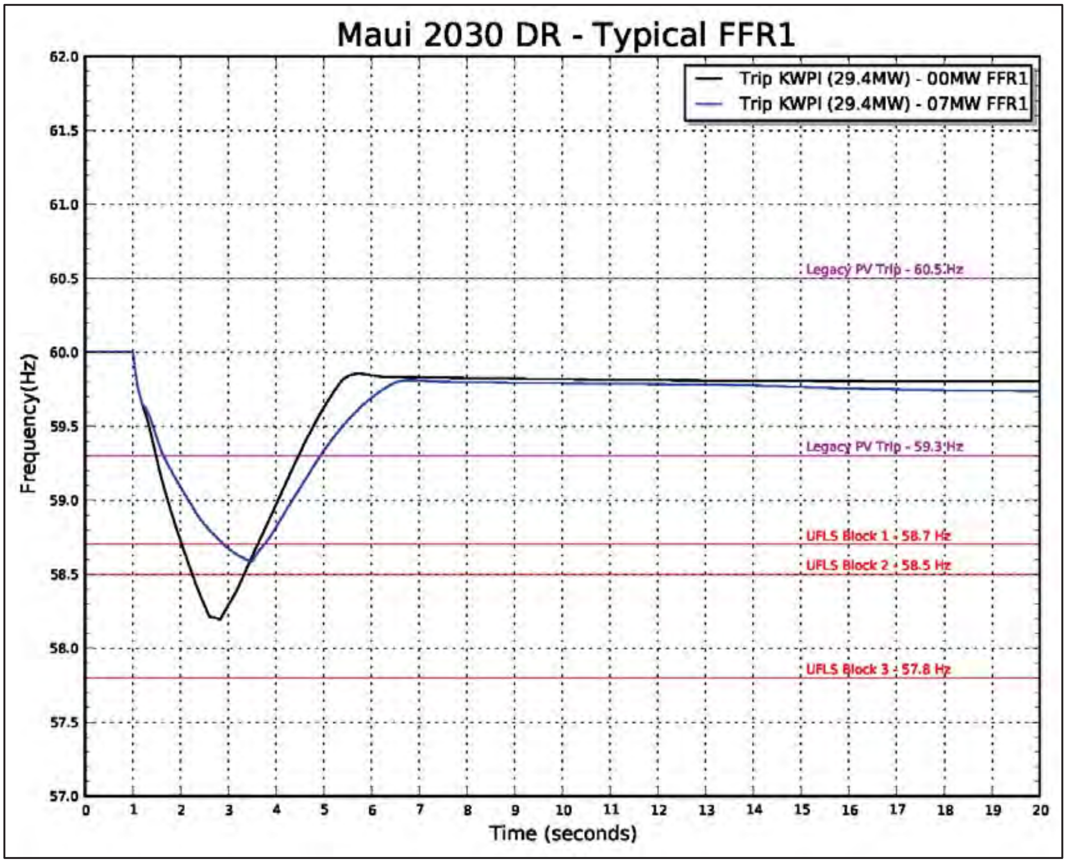

Figure O-283. Frequency Response Profile for FFR1 Typical Hour

Figure O-283 shows the frequency response profile for a KWP 1 trip at 29.4 MW for a typical hour. System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

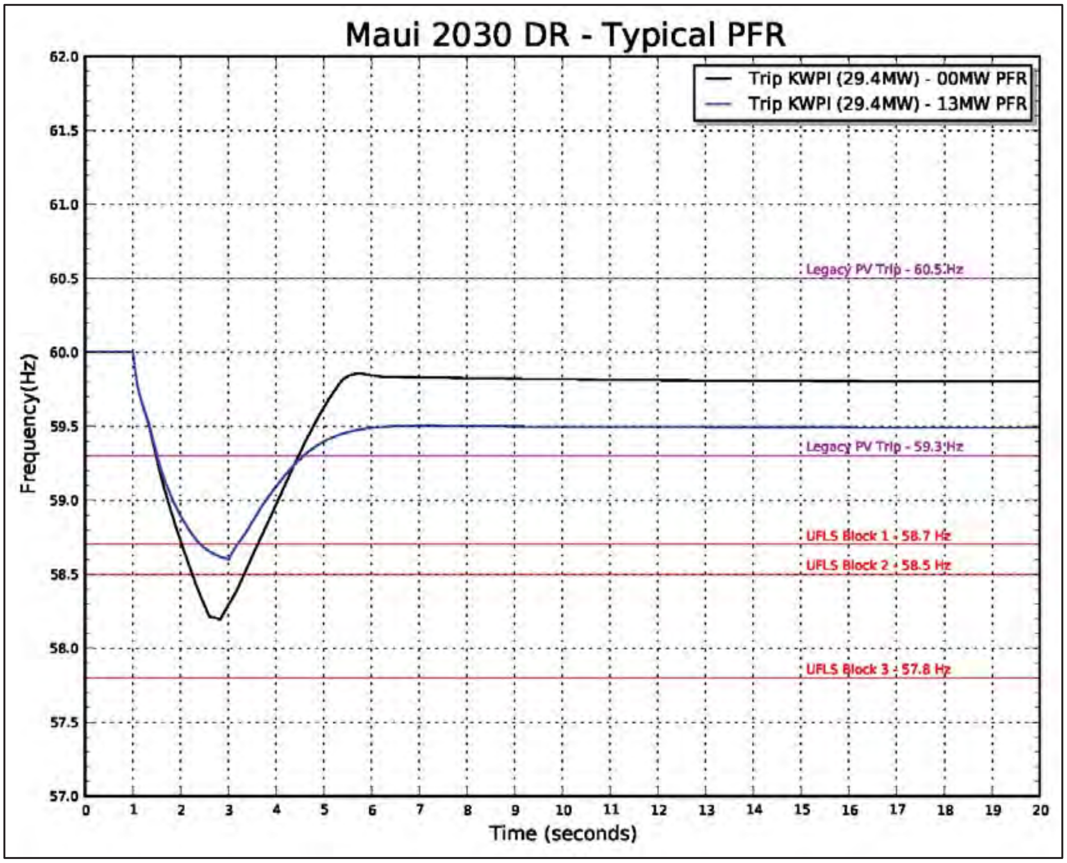

Figure O-284. Frequency Response Profile for PFR Typical Hour

Figure O-284 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 13 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

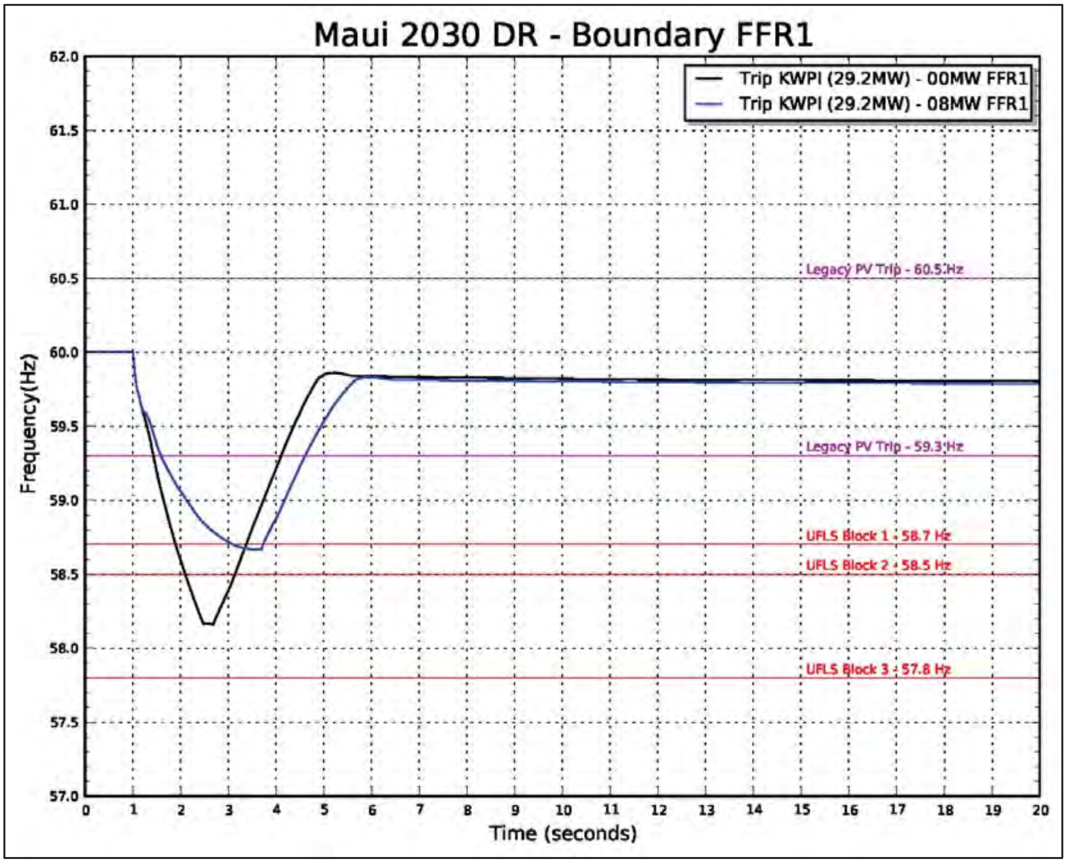

Figure O-285. Frequency Response Profile for FFR1 Boundary Hour

Figure O-285 shows the frequency response profile for a KWP 1 trip at 29.2 MW for a boundary hour. System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

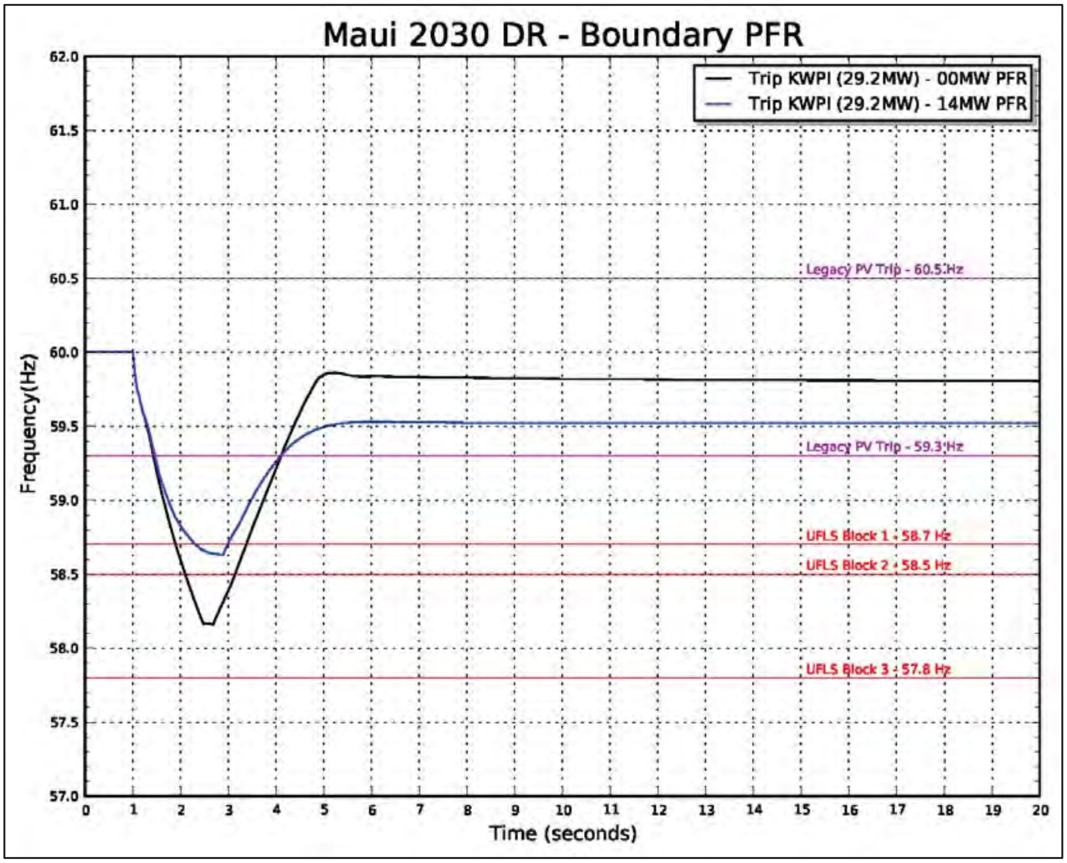

Figure O-286. Frequency Response Profile for PFR Boundary Hour

Figure O-286 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data to represent a boundary condition.

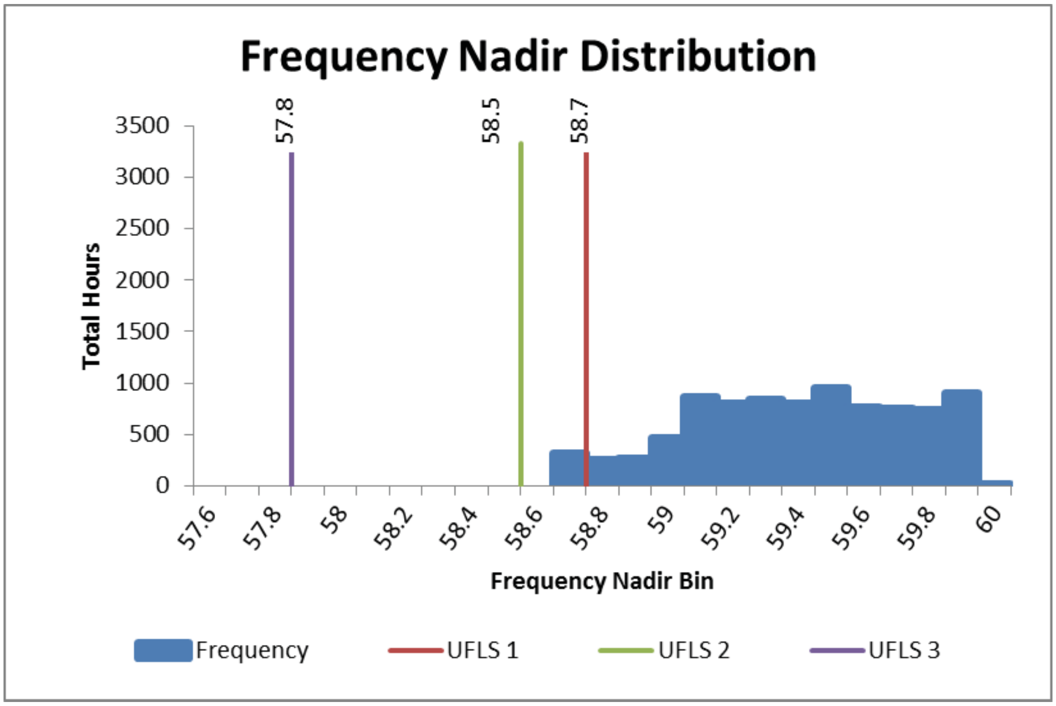

Figure O-287. Frequency Nadir Histogram for 2045

Figure O-287 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a maximum distribution of 323 hours was 8:00 PM on Saturday, July 10. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires one block of UFLS to help stabilize system frequency.

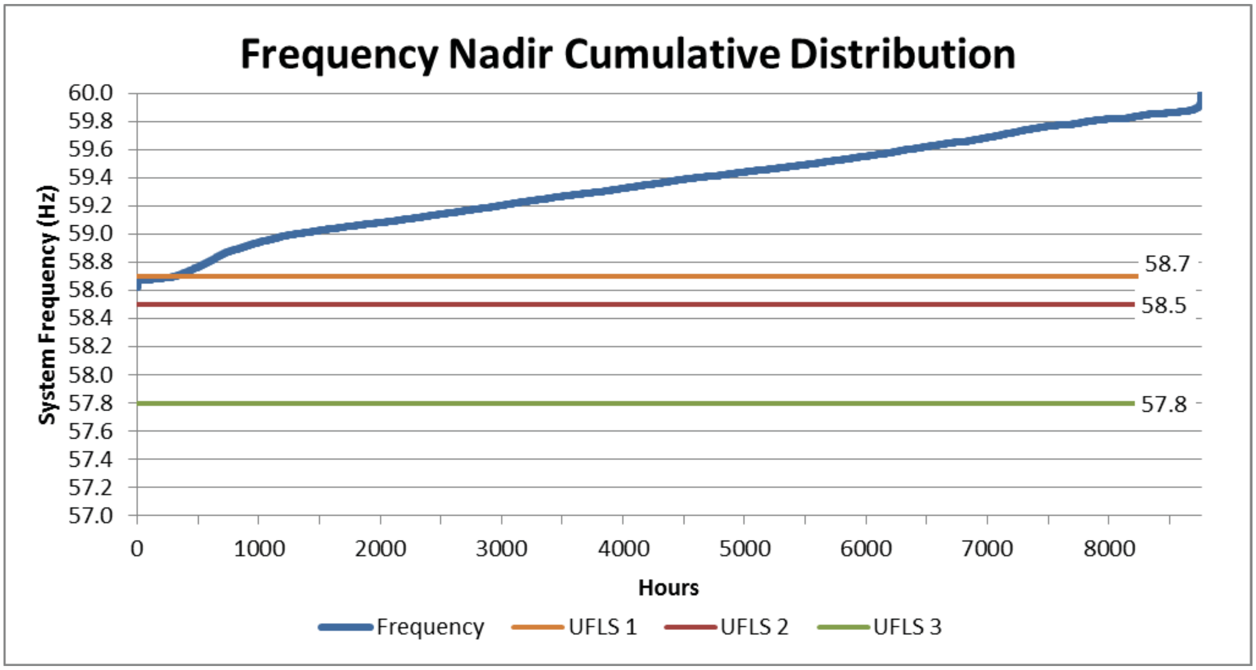

Figure O-288. Frequency Nadir Duration Curve 2045

Figure O-288 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of exceeding the UFLS requirements of TPL-001 for 325 hours of the year.

Unit	Unit Ratings					DR - LS BESS Trip Boundary Sat 7/10/2045 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87			
Geothermal 1	20.0	5.0	3.48	25.0	87	16.4		
Geothermal 2	20.0	5.0	3.48	25.0	87	16.4		
6Hr LS BESS	30.0	0.0			0	30.0		
Maalaea 14	20.0	5.9	2.02	26.8	54			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	0.0	0.0	2.62	6.3	16	*Retired*		
Kahului 2	0.0	0.0	2.62	6.3	16	*Retired*		
Kahului 4	0.0	0.0	1.74	15.6	27	*Retired*		
Kahului 3	0.0	0.0	3.27	13.5	44	*Synchronous Condenser*		
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 3	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	162					119		
-KWP	30	0				21		
-Auwahi	21	0				15		
-KWPII	21	0				19		
-New Wind 1	30	0				21		
-New Wind 2	30	0				22		
-New Wind 3	30	0				22		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	131	0				0		
DER Grid Ex	10	0				0		
Total System MVA						170		
Total Kinetic Energy						403		
Total Load						182		
Total Thermal Generation						63		
Total Renewable Generation						119		
Total Generation						181		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						0		
Total Down Regulation						0		
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-125. Unit Commitment and Dispatch 2045

Table O-125 shows the unit commitment and dispatch for the boundary hour (7/10/45, 8:00 PM)

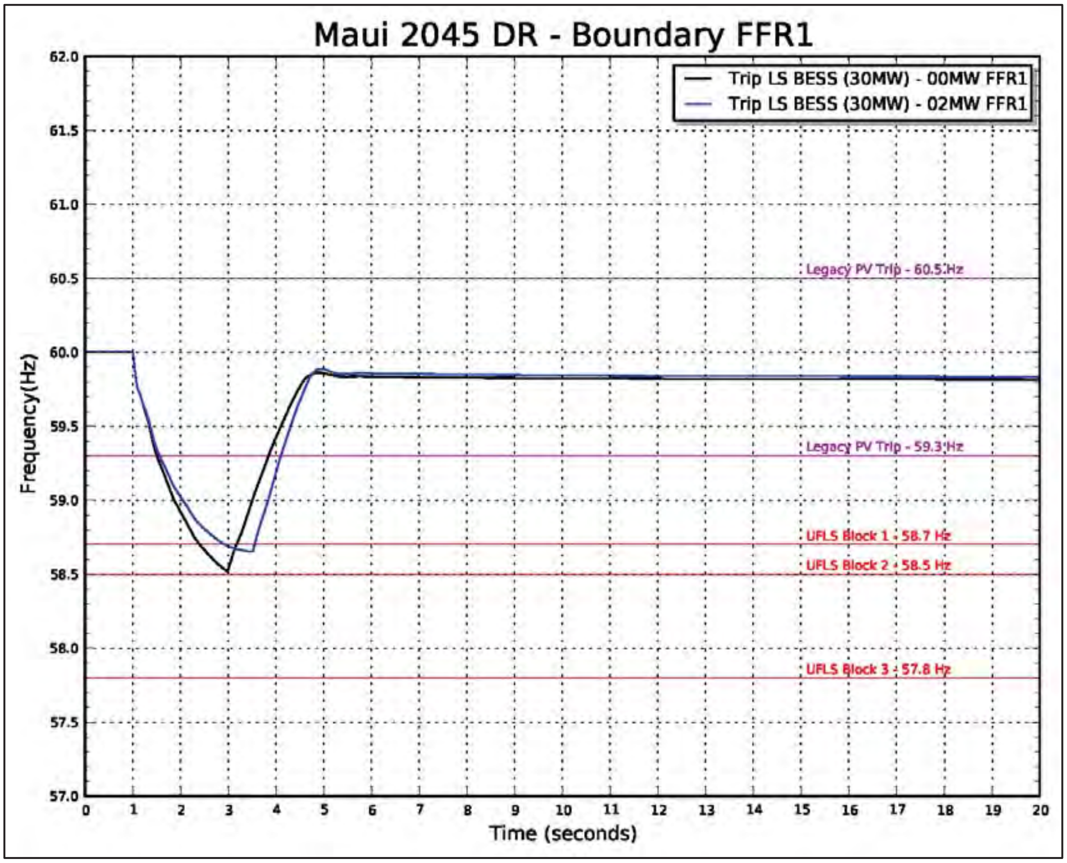

Figure O-289. Frequency Response Profile for FFR1 Boundary Hour

Figure O-289 shows the frequency response profile for a load-shifting BESS trip at 30 MW for a boundary hour . System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 2 MW.

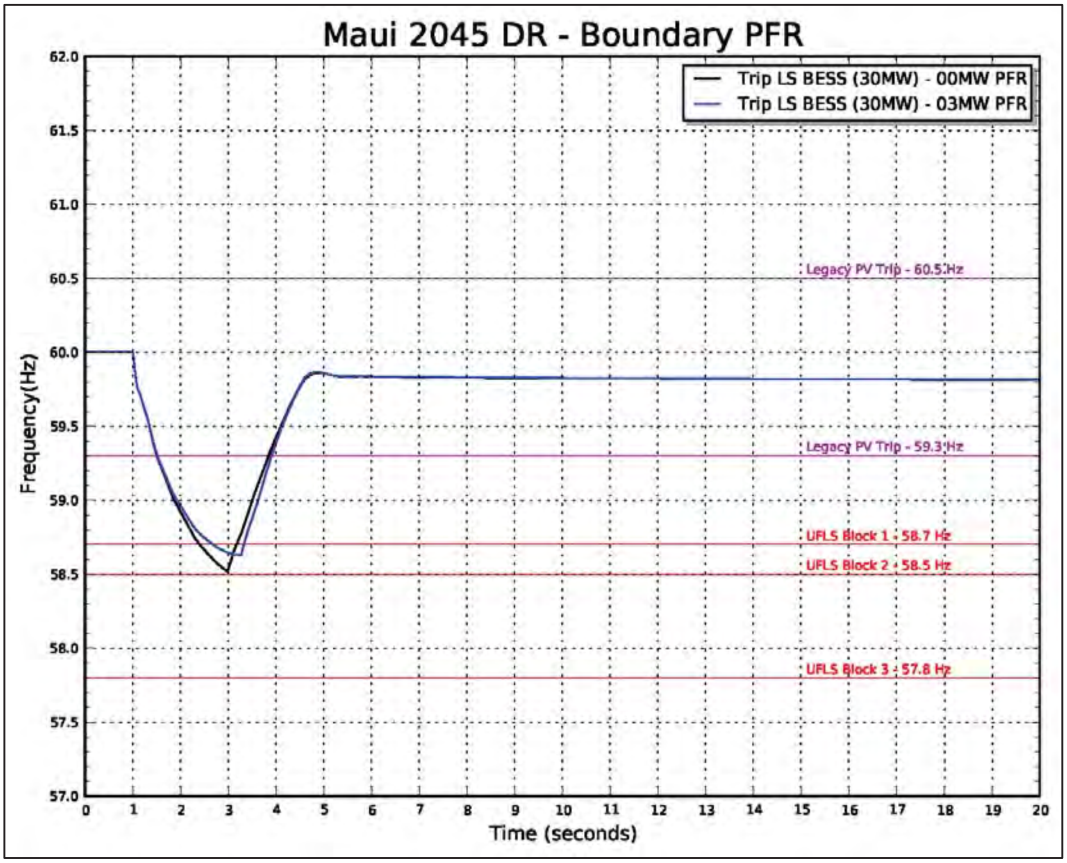

Figure O-290. Frequency Response Profile for PFR Boundary Hour

Figure O-290 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 3 MW.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on the No LNG; High DG-PV plan.

E3 - No LNG; High DG-PV

- Loss of Generation Screening (2019 – 2021): Screening results indicate slightly degraded system performance stating in 2020. The E3 plan has 406 hours that require additional frequency response resources to meet TPL-001. The Post April DR plan has 309 hours. In 2021, E3 has 443 hours compared to 325 hours.
- Loss of Generation Analysis (2019): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 69 kV Fault Analysis (2019): Thirty-one simulations were unstable compared to four simulations for the Post April DR plan.

Maui Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

Minimum Fault Current

A minimum fault current analysis was not performed for Maui. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Maui transmission system requires 72 MVA on the 69 kV system; and 30 MVA on the 23 kV system.

QV Analysis

The Maui transmission system is designed to operate with one transmission line out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability.

Only synchronous generators and synchronous condensers provide fault current to meet the minimum fault current requirements. Therefore, only synchronous condensers are evaluated in these analyses since resource plans tend to displace must-run units.

For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

A new 30 MVA synchronous condenser is required in 2020 for both the Theme 3 No-DR and the Post April DR plans.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition. If screening analysis resulted in limited hours, only a boundary hour was analyzed.

For the Theme 3 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. Table O-203 (page O-616) shows the results of the analysis.

For the Post April DR resource plan, analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Unlike O‘ahu, Maui does not have FFR2 in their Demand Response portfolio. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW. Table O-204 (page O-616) shows the results of the analysis.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Simulations were performed to determine the capacity of PFR required to bring the system into compliance with TPL-001 and to evaluate 5-cycle clearing time to simulate performance of dual pilot or dual differential relay schemes. Table O-126 shows the results of the PFR analysis to bring the system into compliance with TPL-001.

Year	PFR (MW)		
	No DR	No DR w/5 cycle clearing	DR
2019	70	35	48
2020	60	35	70
2021	90	70	38

Table O-126. Summary of Results PFR Analysis

Maui is already in the process of implementing dual differential relays schemes and replacing 69 kV breakers to reduce fault clearing times. Further analysis is required to determine optimal mitigating strategies to maintain system security.

LANA'I SYSTEM SECURITY ANALYSIS

State of the System

The island of Lana'i has a relatively small capacity of DG-PV so system performance has not been adversely affected like the other islands. The 1 MW Lana'i Solar Farm also has a BESS to help regulate frequency.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. Simulations were run for day and night base case dispatches.

Unit	Unit Ratings					Basecase - Miki Basin 7 Trip Day			Basecase - Miki Basin 7 Trip Evening		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43						
LANAI2	1.00	0.50	0.34	1.25	0.43						
LANAI3	1.00	0.50	0.34	1.25	0.43						
LANAI4	1.00	0.50	0.34	1.25	0.43						
LANAI5	1.00	0.50	0.34	1.25	0.43						
LANAI6	1.00	0.50	0.34	1.25	0.43						
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50	2.00	0.20	1.70
L8,D-8	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50	2.00	0.20	1.70
CHP	0.83	0.00	0.34	1.25	3.03	0.83			0.83		
DG-PV	1.57	0.00				0.29	0.46		0.00	0.00	
LSR PV	1.00	0.00				0.80	0.80		0.00	0.00	
Total System MVA							6.75			6.75	
Total Kinetic Energy							9.08			9.08	
Total Load							5.69			4.83	
Total Thermal Generation							4.43			4.83	
Total Renewable Generation							1.26			0.00	
Total Generation							5.69			4.83	
Excess Generation							0.00			0.00	
Total Up Regulation							0.80			0.40	
Total Down Regulation							3.00			3.40	
Legacy DG-PV	59.3Hz Capacity				0.10	59.3Hz Output		0.07	59.3Hz Output		0.00
	60.5Hz Capacity				0.46	60.5Hz Output		0.30	60.5Hz Output		0.00

Table O-127. Unit Commitment and Dispatch 2017

Table O-127 shows the unit commitment and dispatch schedules for the daytime and nighttime base case simulations.

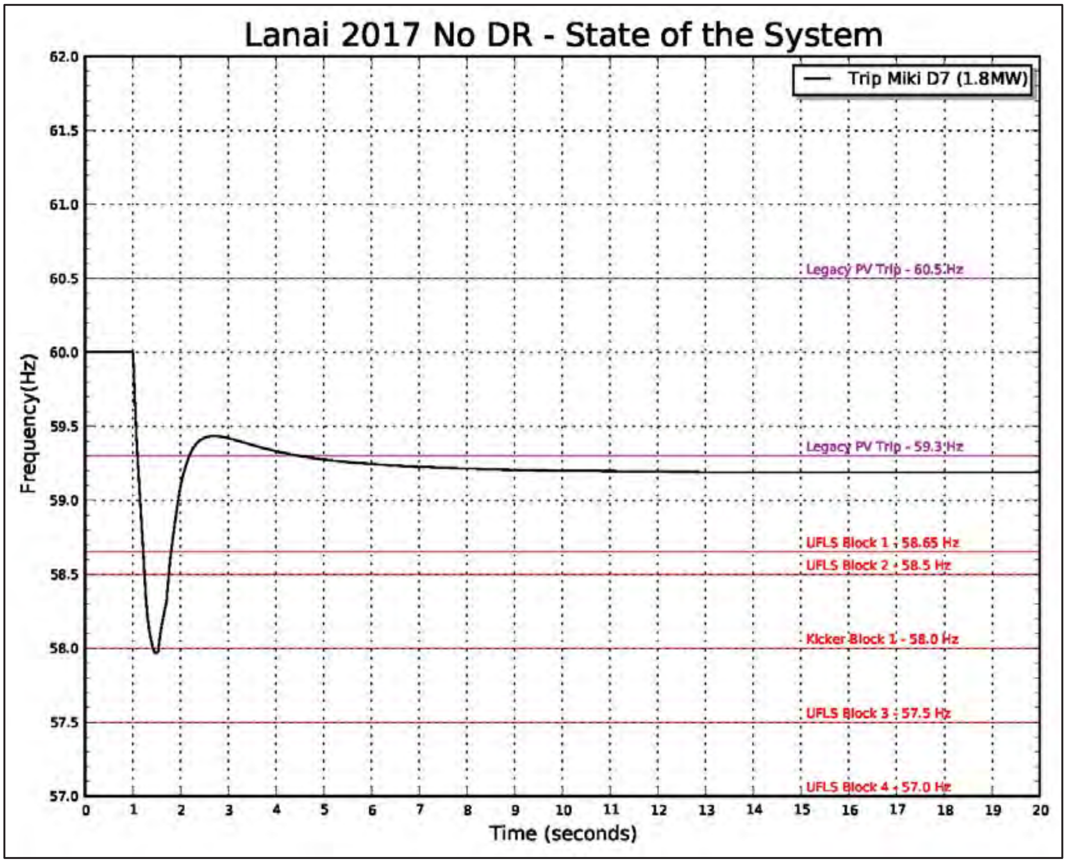

Figure O-291. Frequency Response Profile Day Base Case

Figure O-291 shows the frequency response profile for a Miki Basin diesel engine trip at 1.8 MW during the day. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV that will disconnect from the system is 460 kW. The frequency breaches 58.0 Hz and two blocks of UFLS are required to stabilize system frequency.

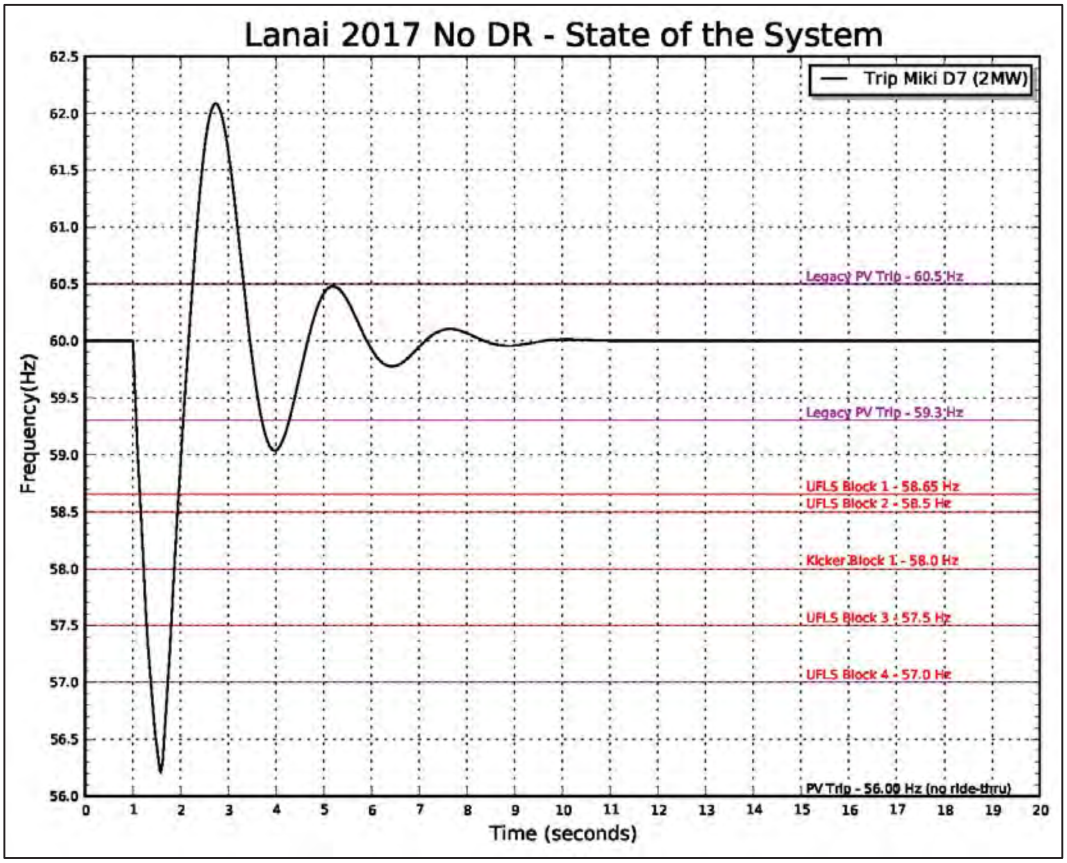

Figure O-292. Frequency Response Profile Night Base Case

Figure O-292 shows the frequency response profile for a Miki Basin diesel engine trip at 2.0 MW during the night. System kinetic energy is 9.1 MW-sec. The frequency breaches 56.4 Hz and four blocks of UFLS are required to stabilize system frequency.

12kV Fault Simulation

Simulations were performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Palaʻau is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Palaʻau are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	**Unit Ratings**					**Basecase - Fault Day**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50
L8,D-8	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
DG-PV	1.57	0.00				0.29	0.46	
LSR PV	1.00	0.00				0.80	0.80	
Total System MVA						6.75		
Total Kinetic Energy						9.08		
Total Load						5.69		
Total Thermal Generation						4.43		
Total Renewable Generation						1.26		
Total Generation						5.69		
Excess Generation						0.00		
Total Up Regulation						0.80		
Total Down Regulation						3.00		
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.07
	60.5Hz Capacity			0.46		60.5Hz Output		0.30

Table O-128. Unit Commitment and Dispatch Fault Analysis 2017

Table O-128 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.26 MW.

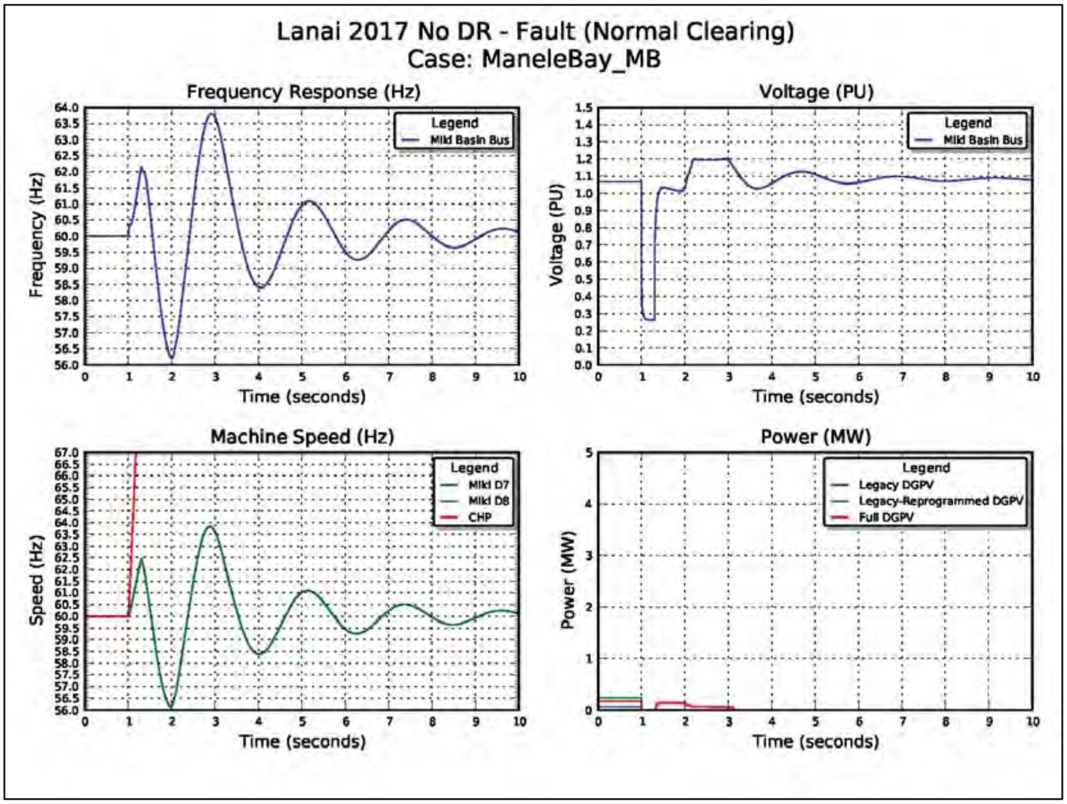

Figure O-293. System Performance Normally Cleared Fault

Figure O-293 shows the system performance for a normally cleared fault on the Manele Bay distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where 460 kW inverter-based generation drops to zero. System frequency swings from a nadir of 56.0 Hz to an apex of 64.0 Hz but the oscillation eventually dampens. Four blocks of UFLS are required to help stabilize system frequency. The system maintains stability for all distribution circuit faults.

Post April Plan

System security analysis was performed on the Post April DR plan include loss of generation analysis and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

The Lana'i system is a nominal 12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. Distribution system reliability is driven by CAID and SAID indices as opposed to equivalent forced outage rate (EFOR). Therefore, the reliability criterion that was used for the frequency response analysis is to prevent system collapse and to maintain acceptable stability margin.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

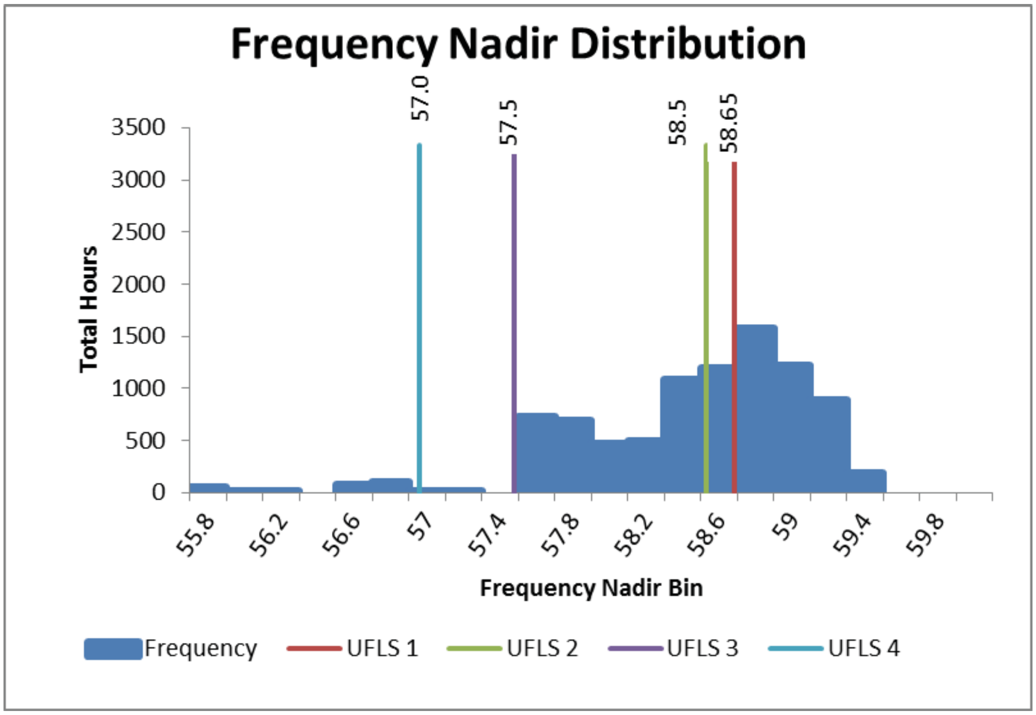

Figure O-294. Frequency Nadir Histogram

Figure O-294 Figure O-295is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the production simulations. The boundary hour selected from a minimum distribution of 231 hours was 4:00 PM on Friday, October 18. The frequency nadir range for the boundary hour is > 57.0 Hz.

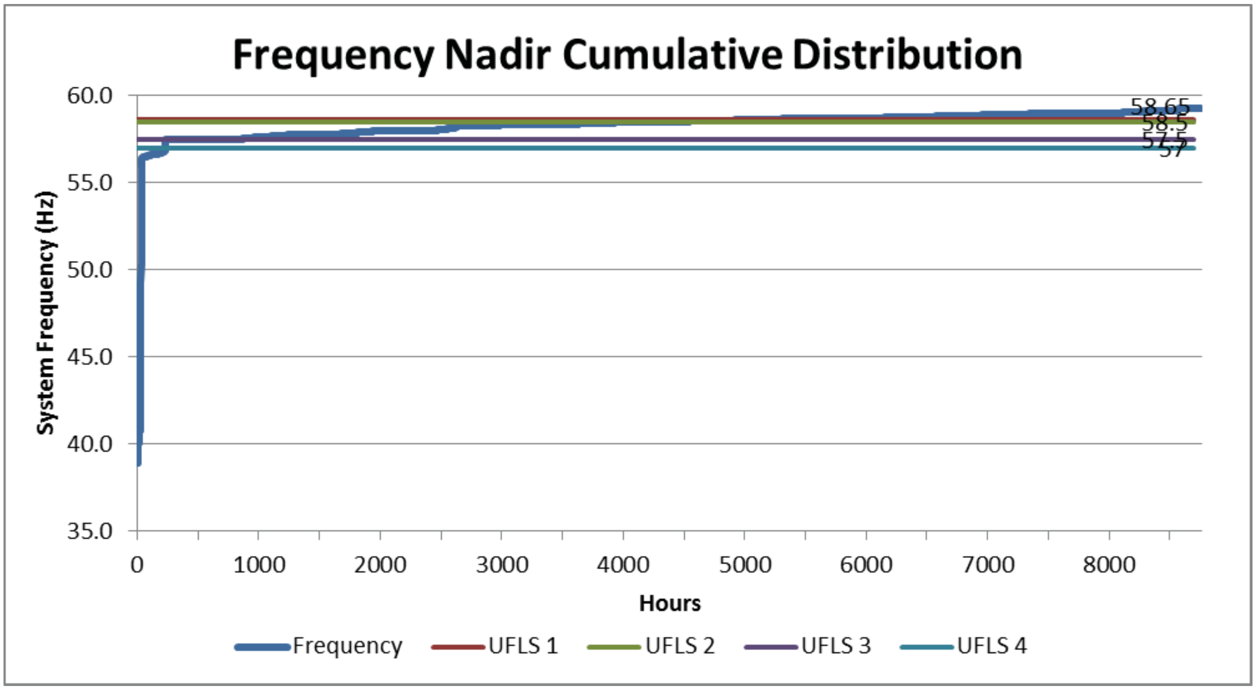

Figure O-295. Frequency Nadir Duration Curve

Figure O-295 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of deploying all four blocks of UFLS for 231 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 7 Trip Boundary 10/18/19 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.24	0.96	0.94
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	1.57	0.00				0.54		
LSR PV	1.00	0.00				0.88		
Total System MVA						6.75		
Total Kinetic Energy						9.08		
Total Load						3.50		
Total Thermal Generation						2.07		
Total Renewable Generation						1.42		
Total Generation						3.49		
Excess Generation						-0.01		
Total Up Regulation						0.96		
Total Down Regulation						0.94		
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.04
	60.5Hz Capacity			0.46		60.5Hz Output		0.19

Table O-129. Unit Commitment and Dispatch 2019

Table O-129 shows the unit commitment and dispatch for the boundary hour (10/18/19, 2:00 PM).

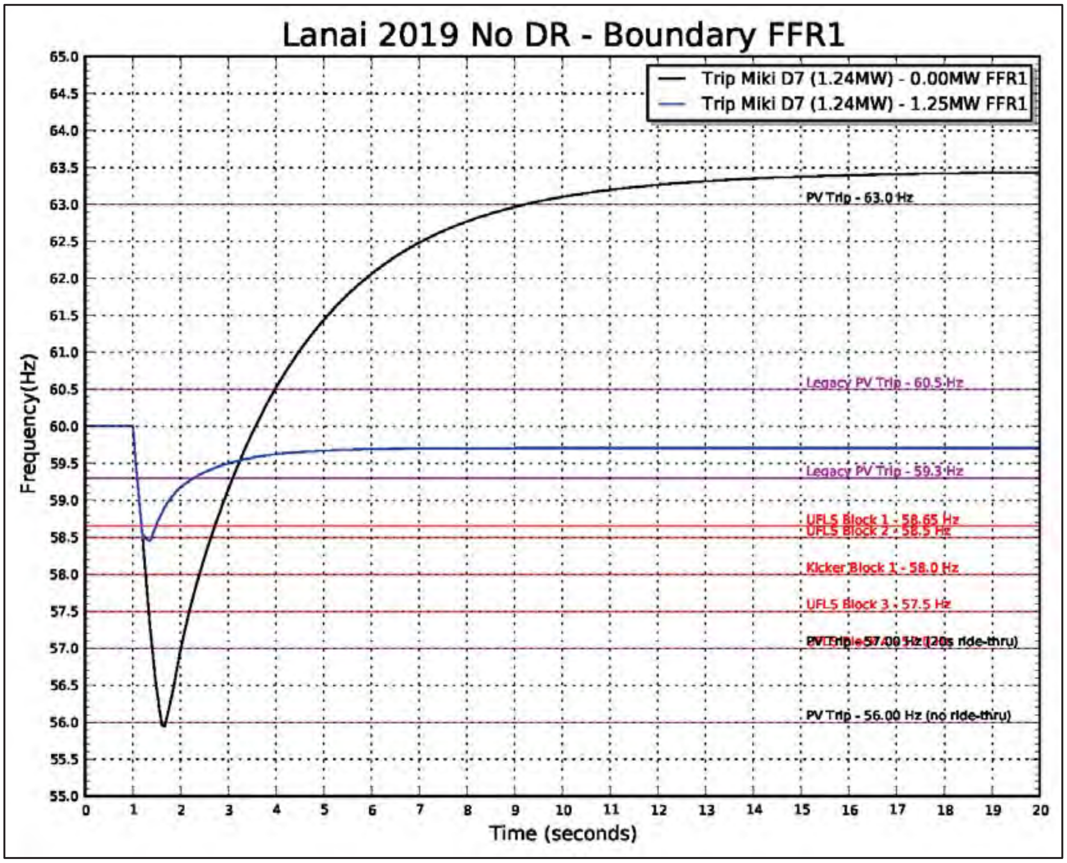

Figure O-296. Frequency Response Profile FFR1

Figure O-296 shows the frequency response profile for a Miki Basin 7 trip at 1.24 MW for a boundary hour. System kinetic energy is 9.1 MW-sec. The capacity of legacy PV is negligible. The frequency nadir breaches 56.0 Hz and four blocks of UFLS are required to stabilize system frequency but the aggregate response over-compensates and drives the frequency apex to 63.5 Hz; a 7.5 Hz peak-to-peak swing. The capacity of FFR1 required to stabilize system frequency is 1.25 MW.

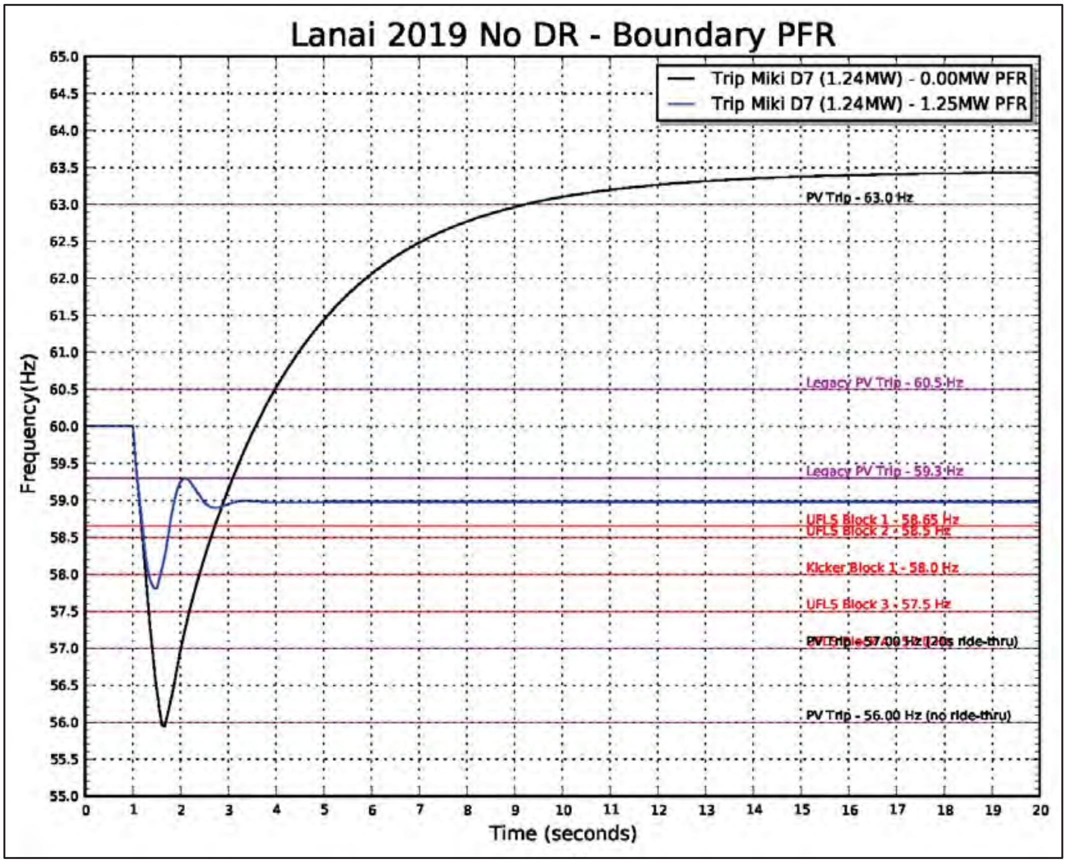

Figure O-297. Frequency Response Profile PFR

Figure O-297 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 1.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Palaʻau is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Palaʻau are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	Unit Ratings					No DR - Fault 3/18/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43	0.50	0.50	0.00
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43	0.57	0.43	0.07
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	1.57	0.00				1.13		
LSR PV	1.00	0.00				0.85		
Total System MVA							6.50	
Total Kinetic Energy							6.91	
Total Load							3.88	
Total Thermal Generation							1.90	
Total Renewable Generation							1.98	
Total Generation							3.88	
Excess Generation							0.00	
Total Up Regulation							0.93	
Total Down Regulation							0.07	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.08
	60.5Hz Capacity			0.46		60.5Hz Output		0.39

Table O-130. Unit Commitment and Dispatch Fault Analysis 2019

Table O-130 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.98 MW.

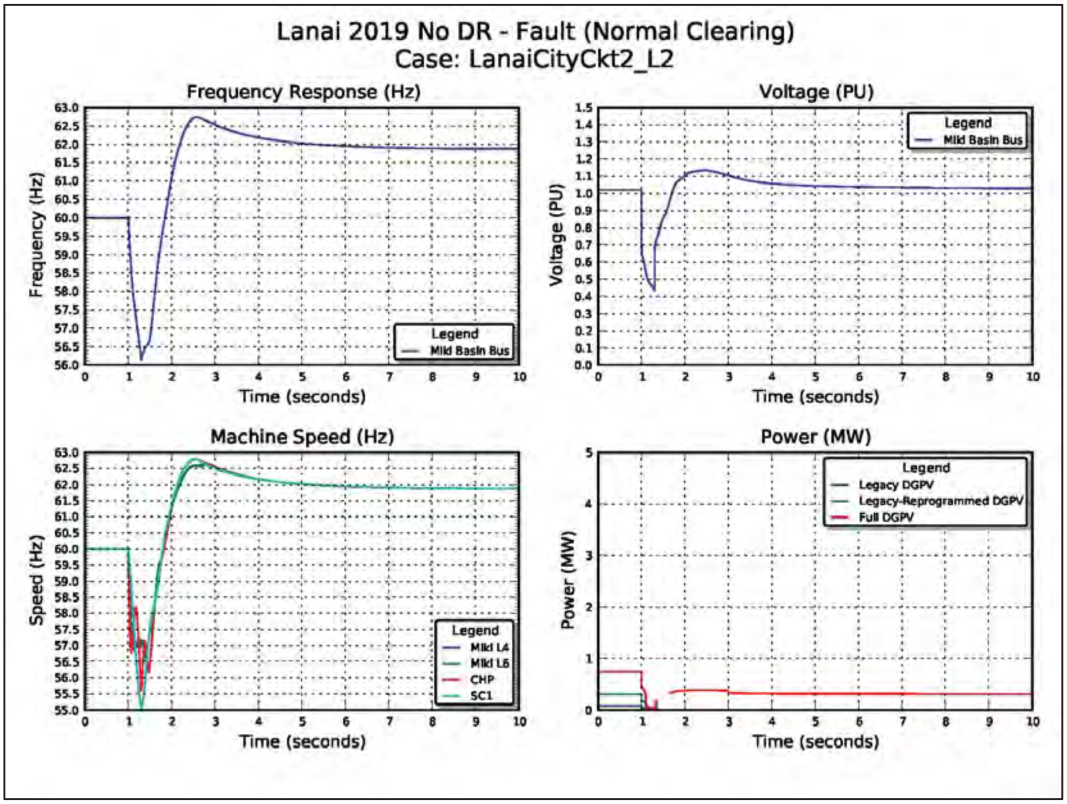

Figure O-298. System Performance Normally Cleared Fault

Figure O-298 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.13 MW from inverter-based generation drops to zero. System frequency initially decreases but the aggregate response of the remaining diesel unit, four blocks of UFLS, and restoration of DG-PV over-compensates and drives the frequency apex above 62.5 Hz. The system maintains stability for all distribution circuit faults.

2020

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

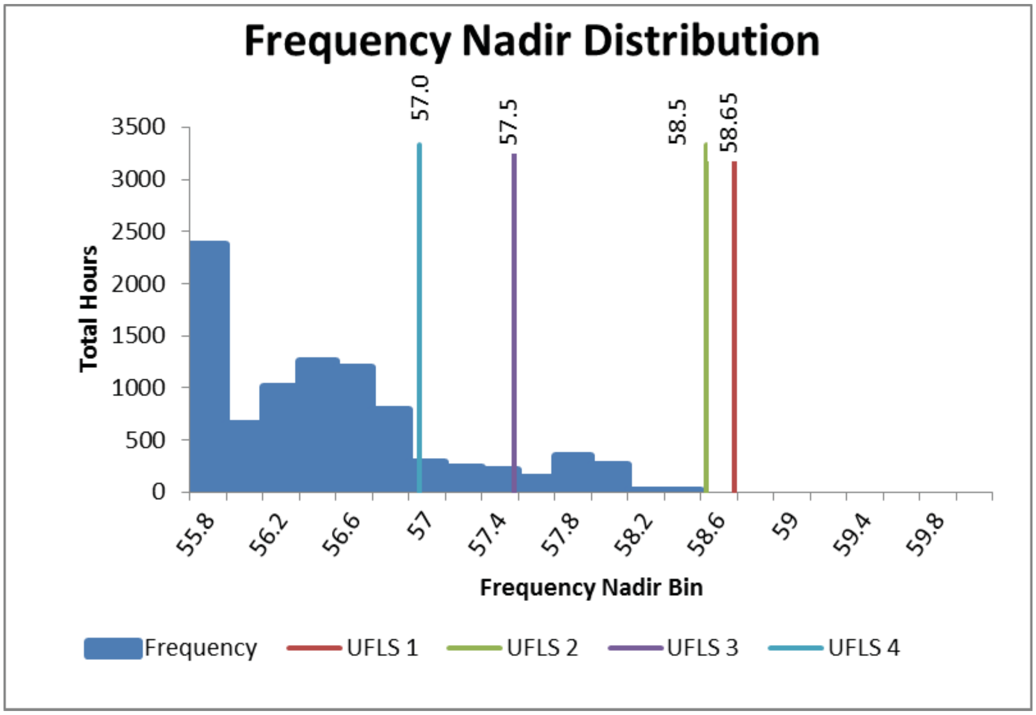

Figure O-299. Frequency Nadir Histogram 2020

Figure O-299 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7543 hours was 4:00 PM on Monday, December 7. The frequency nadir range for the boundary hour is > 57.0 Hz.

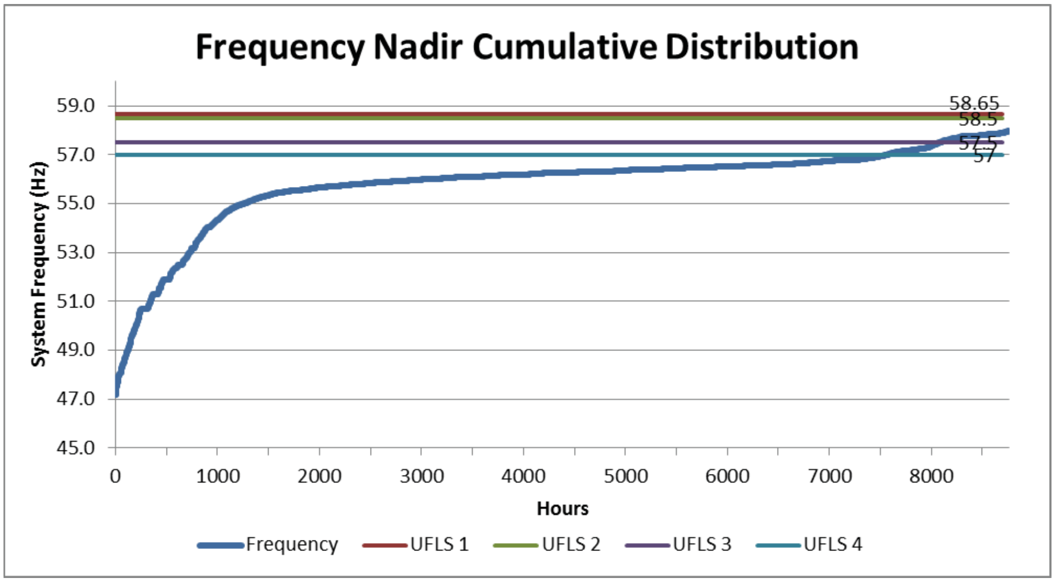

Figure O-300. Frequency Nadir Duration Curve 2020

Figure O-300 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of deploying all four blocks of UFLS for 7543 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 12/7/20 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.20	0.00	1.90
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				0.45		
LSR PV	1.00	0.00				0.80		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							4.28	
Total Thermal Generation							3.03	
Total Renewable Generation							1.26	
Total Generation							4.29	
Excess Generation							0.01	
Total Up Regulation							0.00	
Total Down Regulation							1.90	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.03
	60.5Hz Capacity			0.46		60.5Hz Output		0.15

Table O-131. Unit Commitment and Dispatch 2020

Table O-131 shows the unit commitment and dispatch for the boundary hour (12/7/20, 4:00 PM).

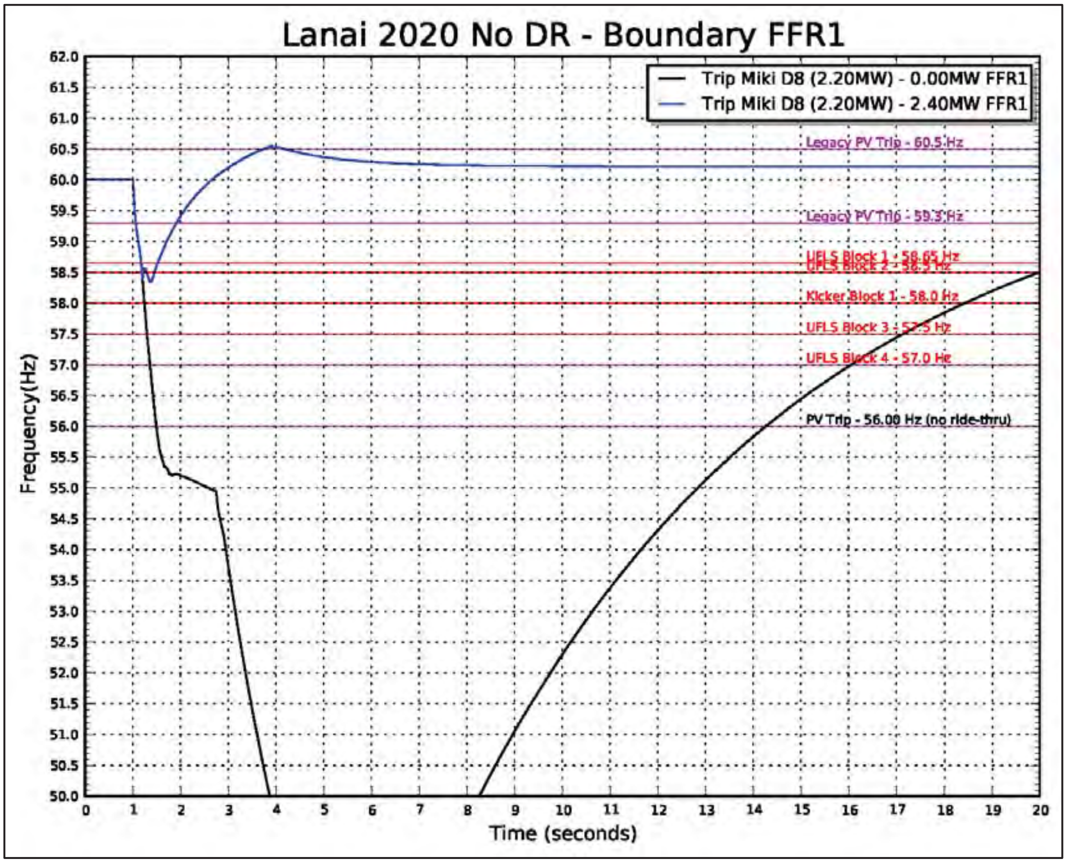

Figure O-301. Frequency Response Profile FFR1

Figure O-301 shows the frequency response profile for a Miki Basin 8 trip at 2.2 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to limit UFLS to two blocks and add a margin of stability is 1.25 MW.

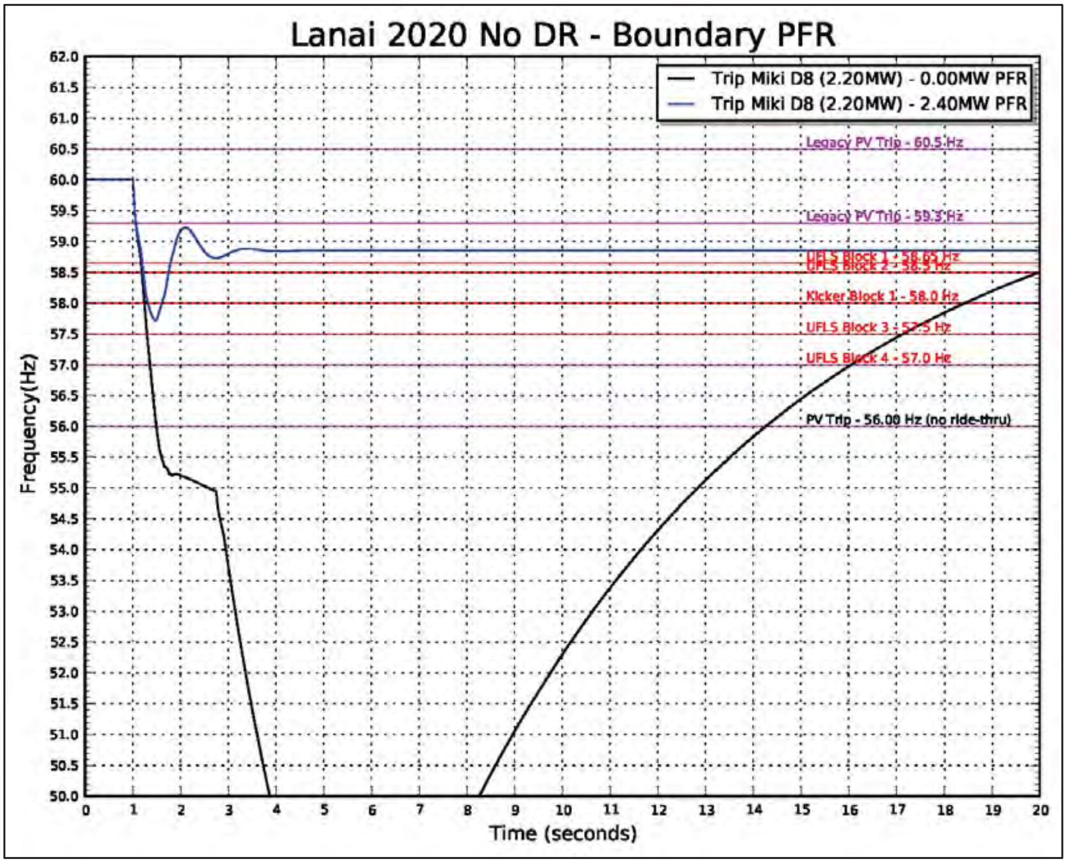

Figure O-302. Frequency Response Profile PFR

Figure O-302 shows the frequency response profile for the PFR analysis. The capacity of PFR required to add stability to the system is 2.4 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Pala'au is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Pala'au are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	Unit Ratings					No DR - Fault 3/10/20 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43	0.51	0.49	0.01
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				1.18		
LSR PV	1.00	0.00				0.91		
Total System MVA						5.25		
Total Kinetic Energy						6.48		
Total Load						3.84		
Total Thermal Generation						1.34		
Total Renewable Generation						2.09		
Total Generation						3.42		
Excess Generation						-0.42		
Total Up Regulation						0.49		
Total Down Regulation						0.01		
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.08
	60.5Hz Capacity			0.46		60.5Hz Output		0.39

Table O-132. Unit Commitment and Dispatch Fault Analysis 2020

Table O-132 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.19 MW.

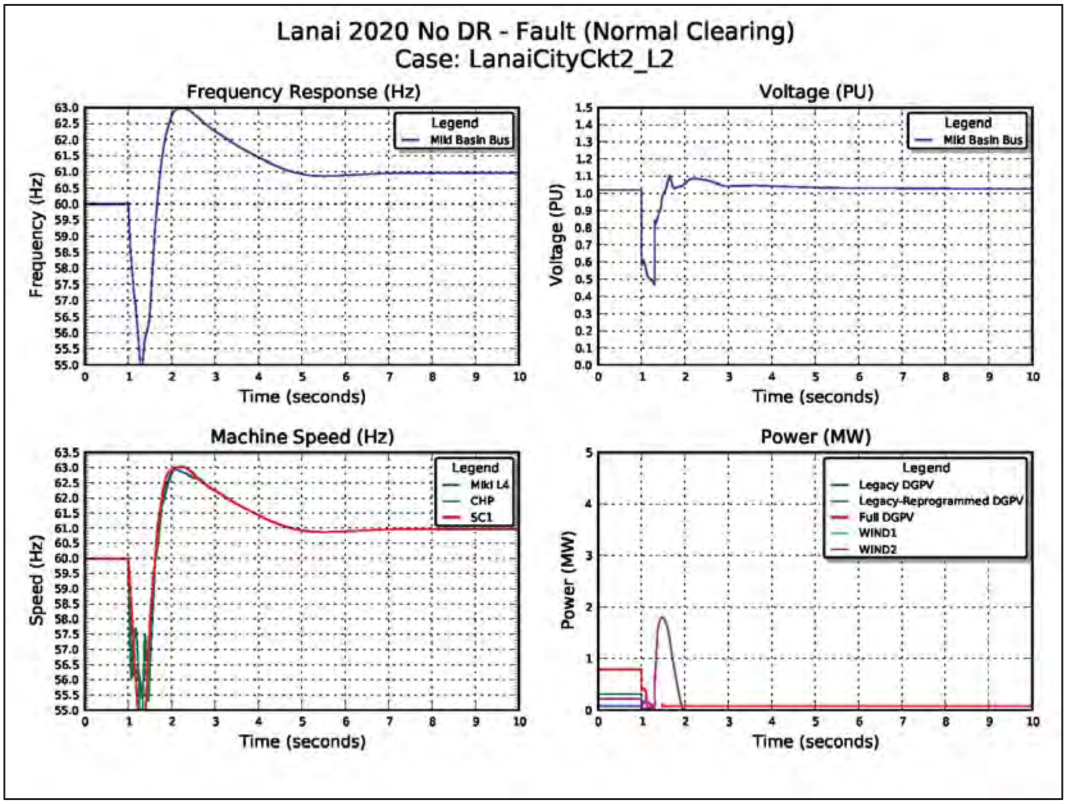

Figure O-303. System Performance Normally Cleared Fault

Figure O-303 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.61 MW from inverter-based generation drops to zero. System frequency initially decreases but the aggregate response of four blocks of UFLS and droop response from the wind farm over-compensates, driving the frequency apex above 63 Hz before stabilizing above 60 Hz. The system maintains stability for all distribution circuit faults.

2021

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

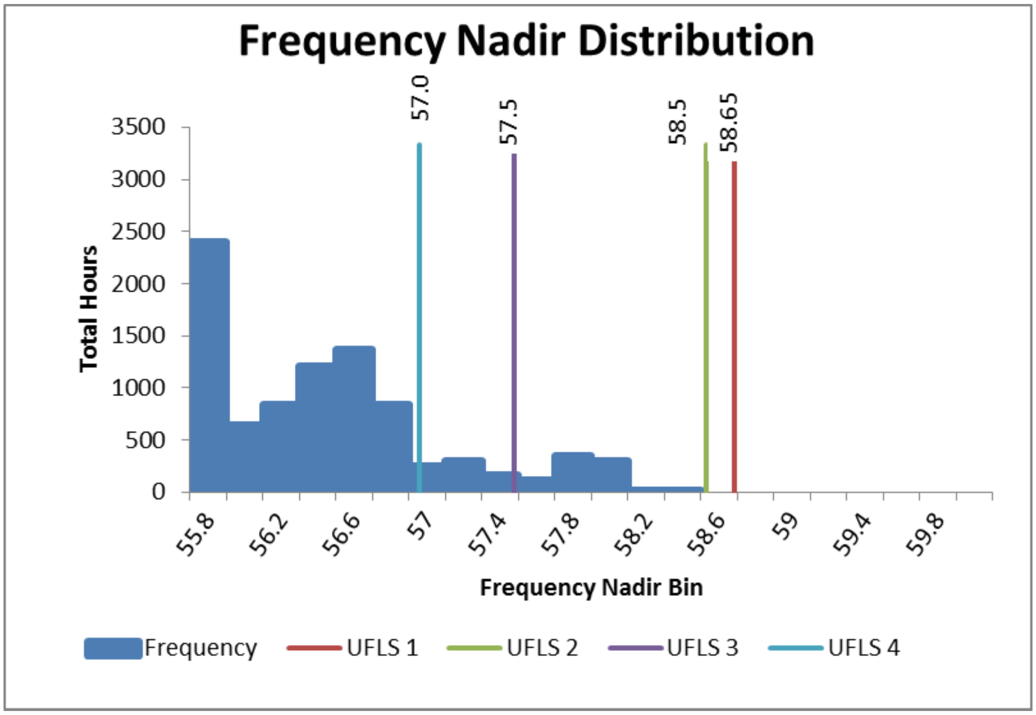

Figure O-304. Frequency Nadir Histogram 2021

Figure O-304 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7518 hours was 4:00 PM on Monday, December 7. The frequency nadir range for the boundary hour is > 57.0 Hz.

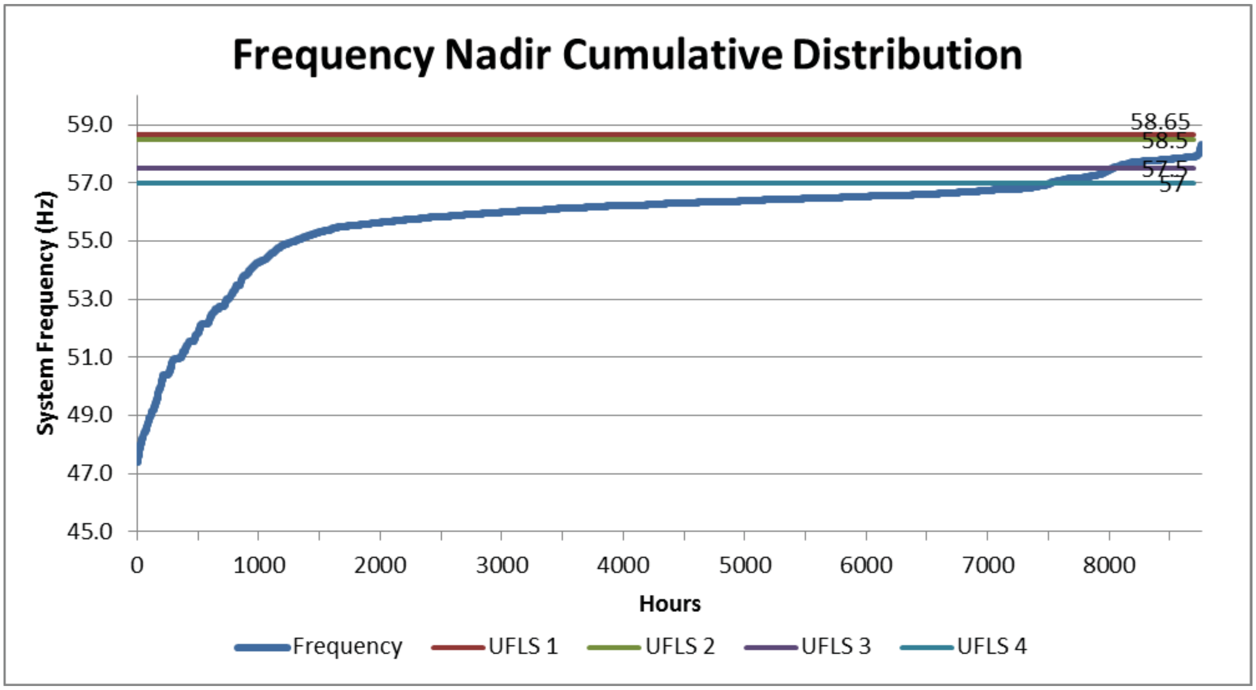

Figure O-305. Frequency Nadir Duration Curve 2021

Figure O-305 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of deploying all four blocks of UFLS for 7518 hours of the year.

Unit	**Unit Ratings**					**No DR - Miki Basin 8 Trip Boundary 12/22/21 Hour 13**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.17	0.03	1.87
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				0.59		
LSR PV	1.00	0.00				0.80		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							4.39	
Total Thermal Generation							3.00	
Total Renewable Generation							1.39	
Total Generation							4.39	
Excess Generation							0.01	
Total Up Regulation							0.03	
Total Down Regulation							1.87	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.04
	60.5Hz Capacity			0.46		60.5Hz Output		0.19

Table O-133. Unit Commitment and Dispatch 2021

Table O-133 shows the unit commitment and dispatch for the boundary hour (12/7/20, 4:00 PM).

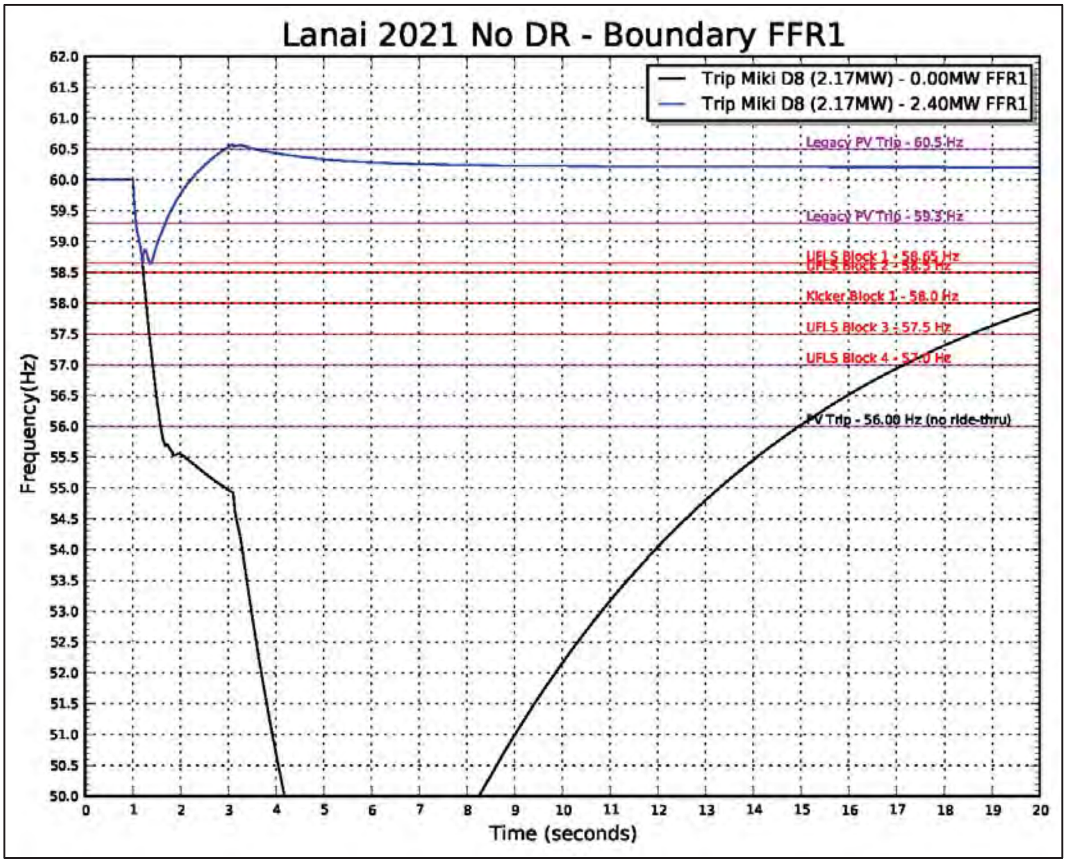

Figure O-306. Frequency Response Profile FFR1

Figure O-306 shows the frequency response profile for a Miki Basin 8 trip at 2.17 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.4 MW.

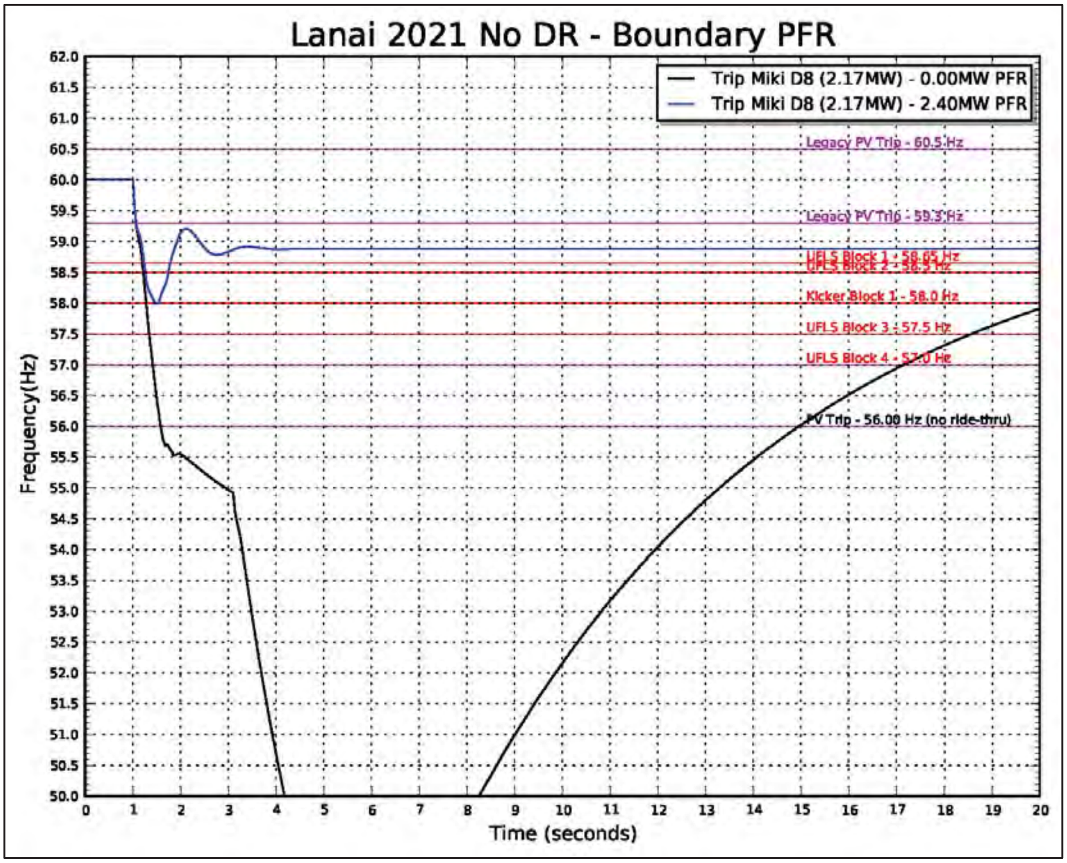

Figure O-307. Frequency Response Profile PFR

Figure O-307 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 2.4 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Palaʻau is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Palaʻau are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	**Unit Ratings**					**No DR - Fault 3/13/21 Hour 13**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.48		
Wind2	2.00	0.00				0.48		
DG-PV	1.68	0.00				1.22		
LSR PV	1.00	0.00				0.89		
Total System MVA						4.00		
Total Kinetic Energy						6.05		
Total Load						3.90		
Total Thermal Generation						0.83		
Total Renewable Generation						3.07		
Total Generation						3.90		
Excess Generation						0.00		
Total Up Regulation						0.00		
Total Down Regulation						0.00		
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.08
	60.5Hz Capacity			0.46		60.5Hz Output		0.39

Table O-134. Unit Commitment and Dispatch Fault Analysis

Table O-134 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 2.11 MW.

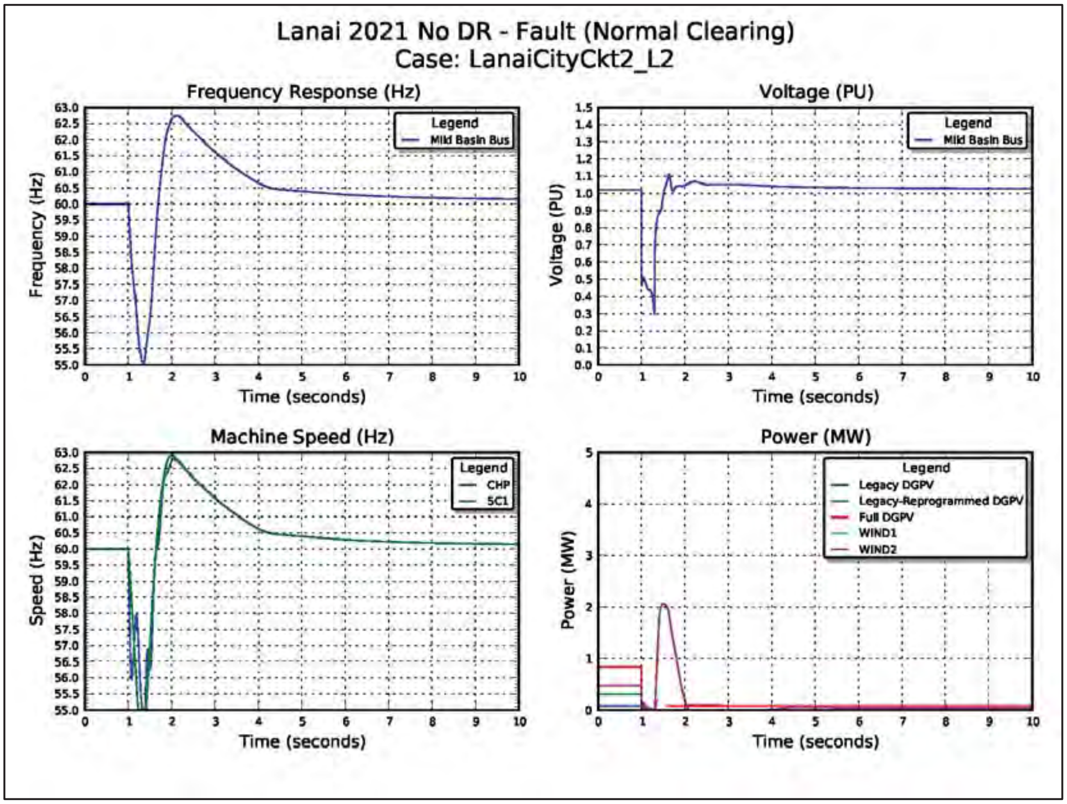

Figure O-308. System Performance Normally Cleared Fault

Figure O-308 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.11 MW from inverter-based generation drops to zero. System frequency initially decreases to 55.0 Hz but the aggregate response of four blocks of UFLS and droop response from the wind farm over-compensates, driving the frequency apex above 62.5 Hz before stabilizing above 60 Hz. The system maintains stability for all distribution circuit faults.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

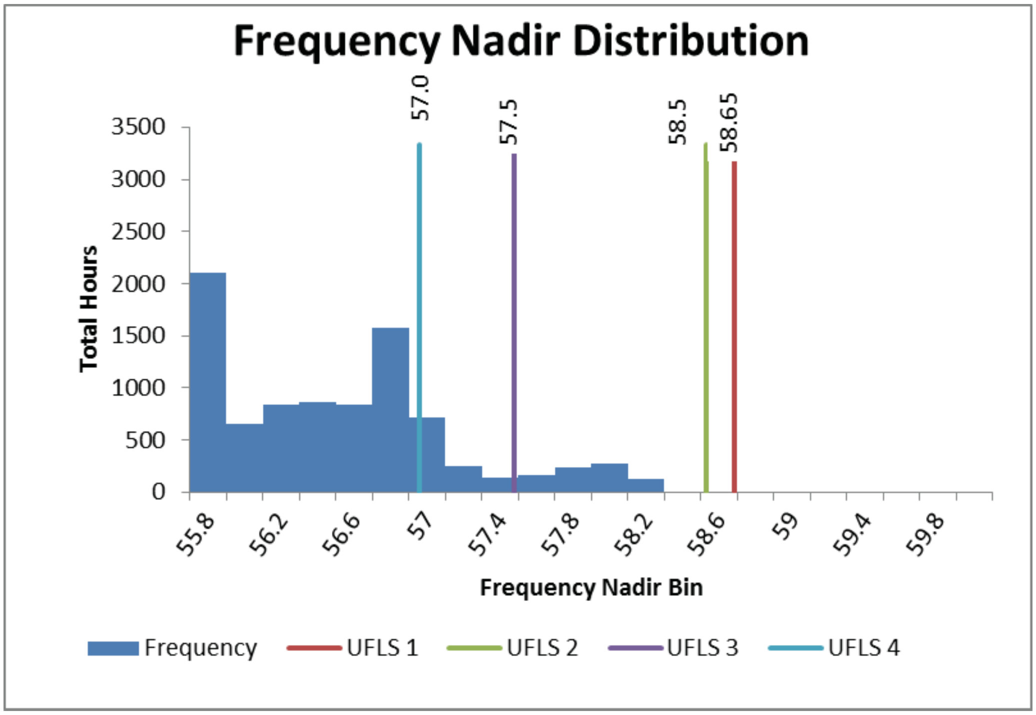

Figure O-309. Frequency Nadir Histogram

Figure O-309 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 4576 hours was 9:00 AM on Tuesday, January 29. The frequency nadir range for the boundary hour is > 57.0 Hz.

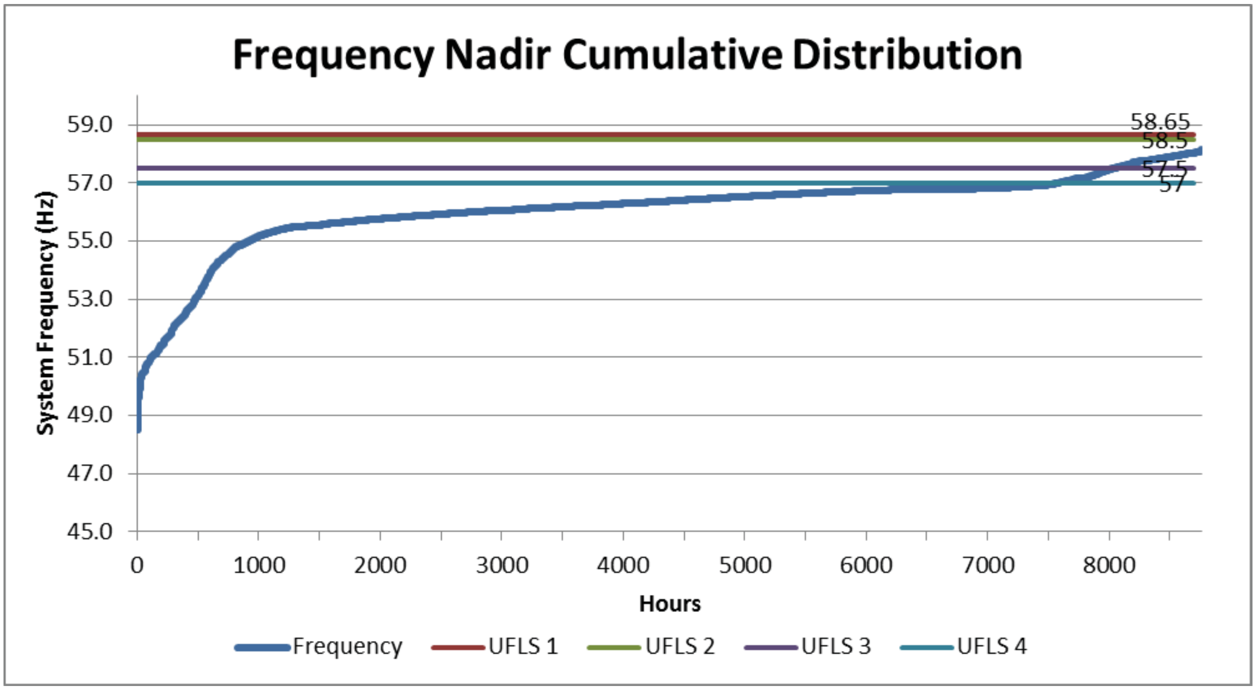

Figure O-310. Frequency Nadir Duration Curve 2030

Figure O-310 shows the frequency nadir duration curve for the resource plan in 2030. The system is at risk of deploying all four blocks of UFLS for 4576 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 1/29/30 Hour 9		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.15	0.05	1.85
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	5.76	0.00				0.35		
LSR PV	1.00	0.00				0.70		
Total System MVA						6.75		
Total Kinetic Energy						9.08		
Total Load						4.02		
Total Thermal Generation						2.98		
Total Renewable Generation						1.04		
Total Generation						4.02		
Excess Generation						0.00		
Total Up Regulation						0.05		
Total Down Regulation						1.85		
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.01
	60.5Hz Capacity			0.46		60.5Hz Output		0.04

Table O-135. Unit Commitment and Dispatch 2030

Table O-135 shows the unit commitment and dispatch for the boundary hour (1/29/30, 9:00 AM).

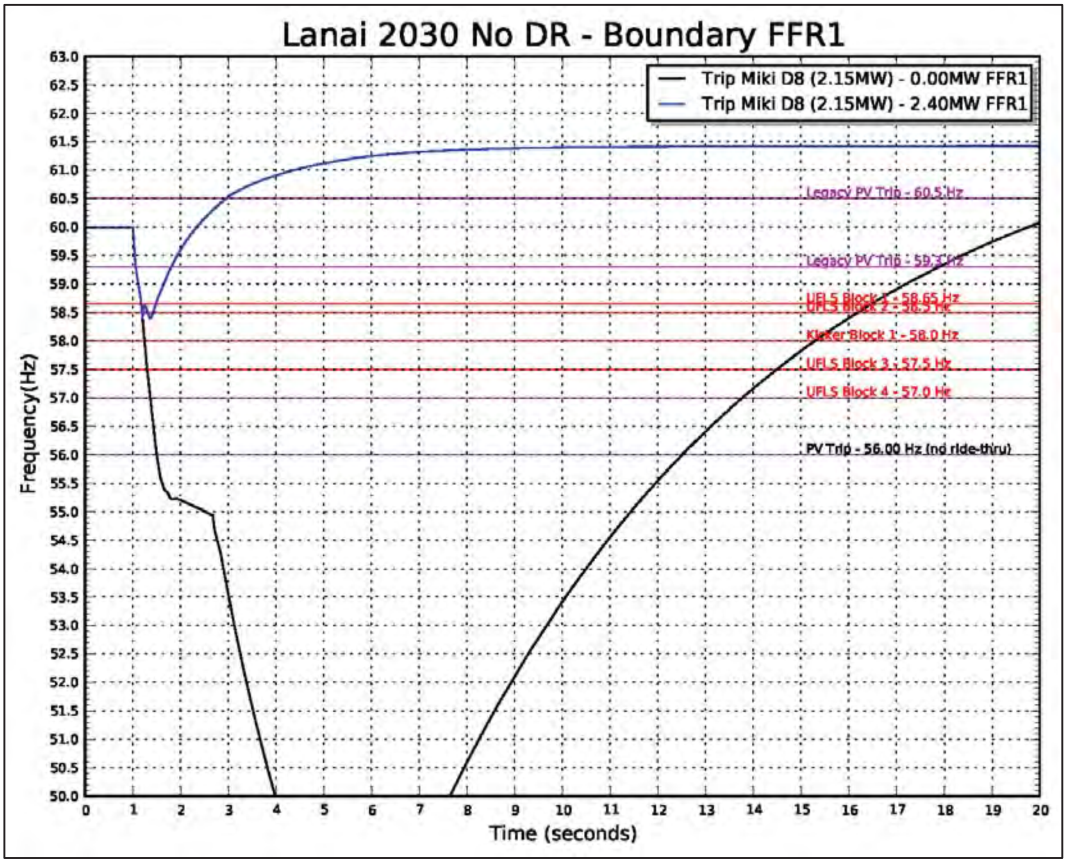

Figure O-311. Frequency Response Profile FFR1

Figure O-311 shows the frequency response profile for a Miki Basin 8 trip at 2.17 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.4 MW.

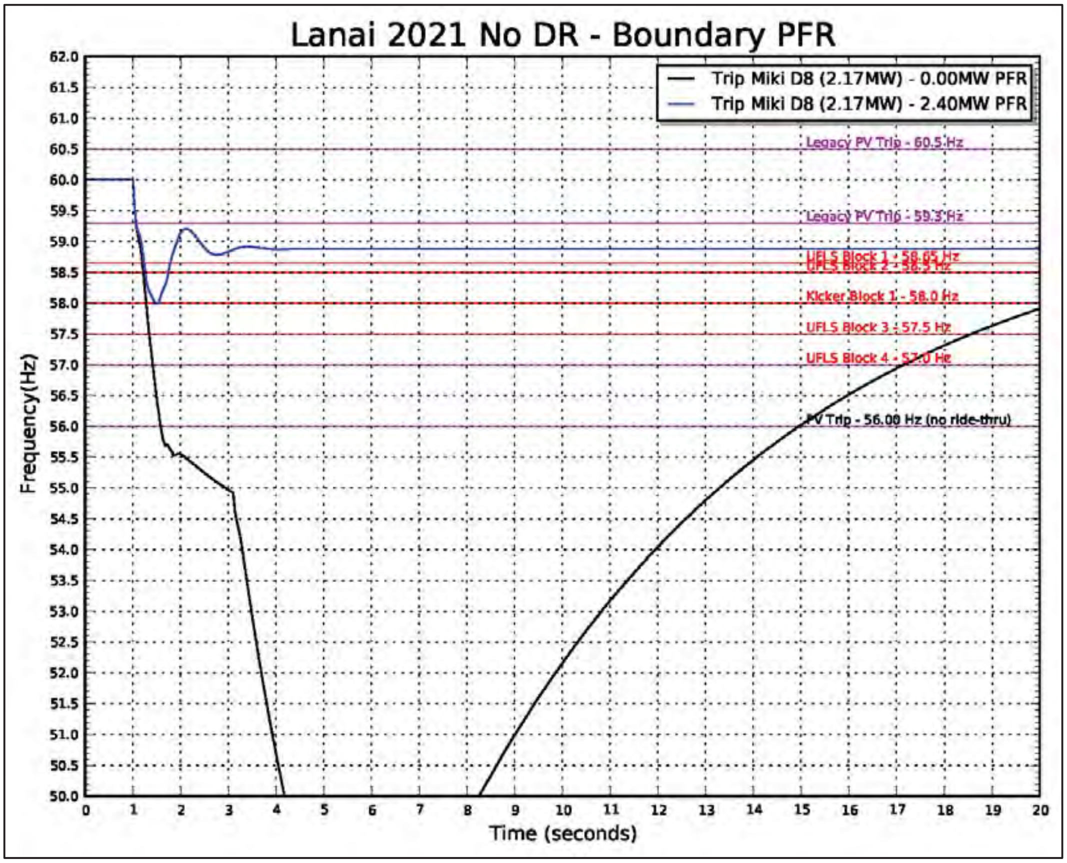

Figure O-312. Frequency Response Profile PFR

Figure O-312 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 2.4 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

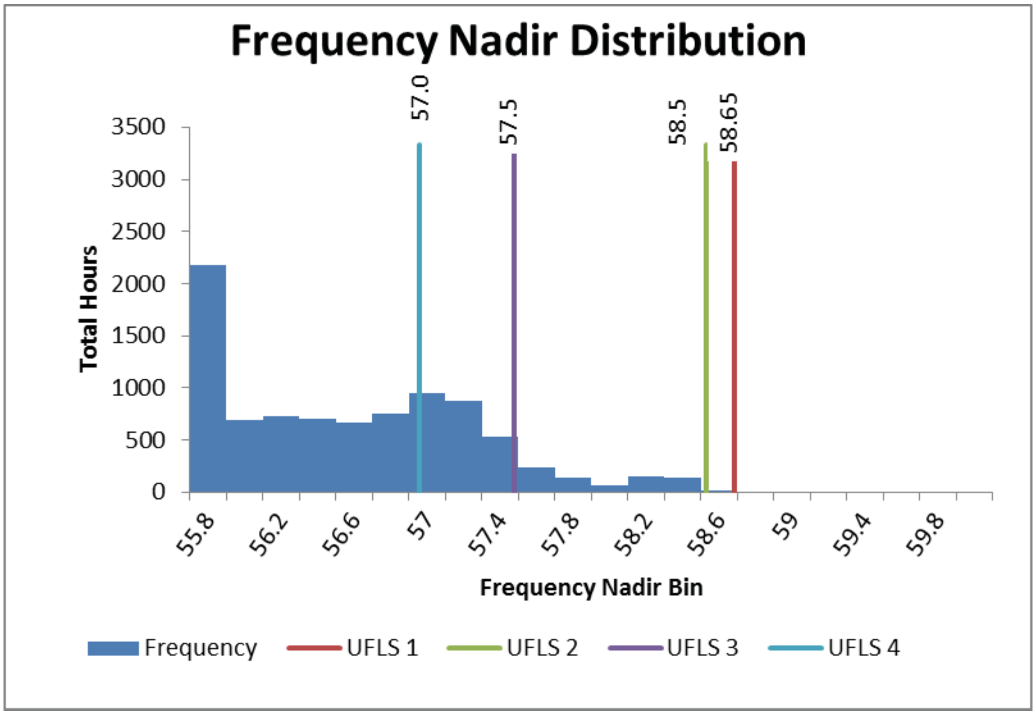

Figure O-313. Frequency Nadir Histogram

Figure O-313 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 6630 hours was4:00 AM on Thursday, February 23. The frequency nadir range for the boundary hour is > 57.0 Hz.

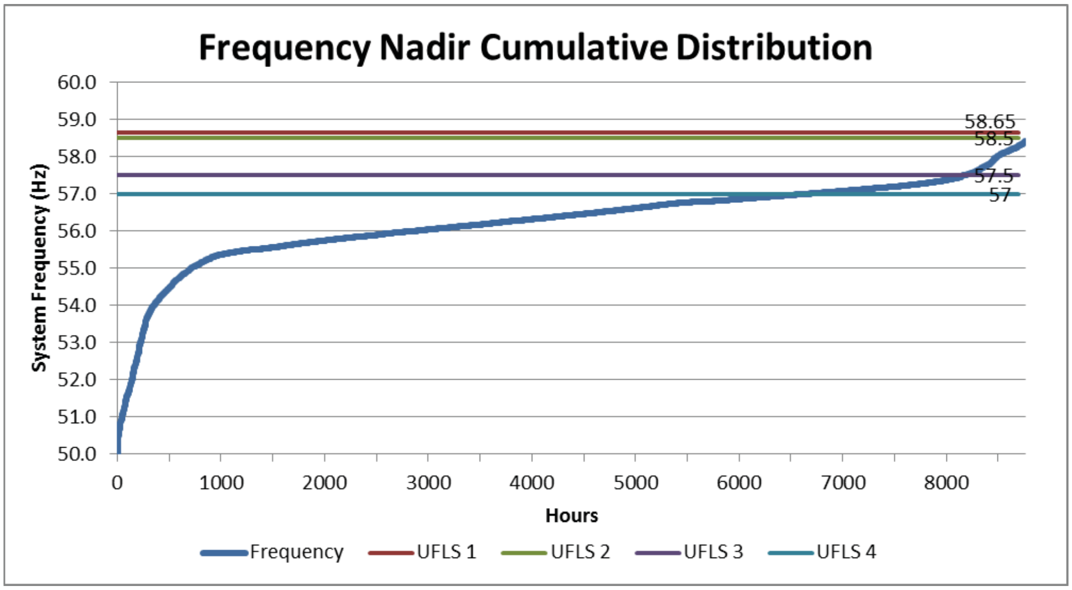

Figure O-314. Frequency Nadir Duration Curve

Figure O-314 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of deploying all four blocks of UFLS for 6630 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 2/23/45 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.15	0.05	1.85
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.01		
Wind2	2.00	0.00				0.01		
DG-PV	11.85	0.00				0.00		
LSR PV	1.00	0.00				0.00		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							3.05	
Total Thermal Generation							2.98	
Total Renewable Generation							0.02	
Total Generation							3.00	
Excess Generation							-0.05	
Total Up Regulation							0.05	
Total Down Regulation							1.85	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.00
	60.5Hz Capacity			0.46		60.5Hz Output		0.00

Table O-136. Unit Commitment and Dispatch 2045

Table O-136 shows the unit commitment and dispatch for the boundary hour (8/6/45, 12:00 PM).

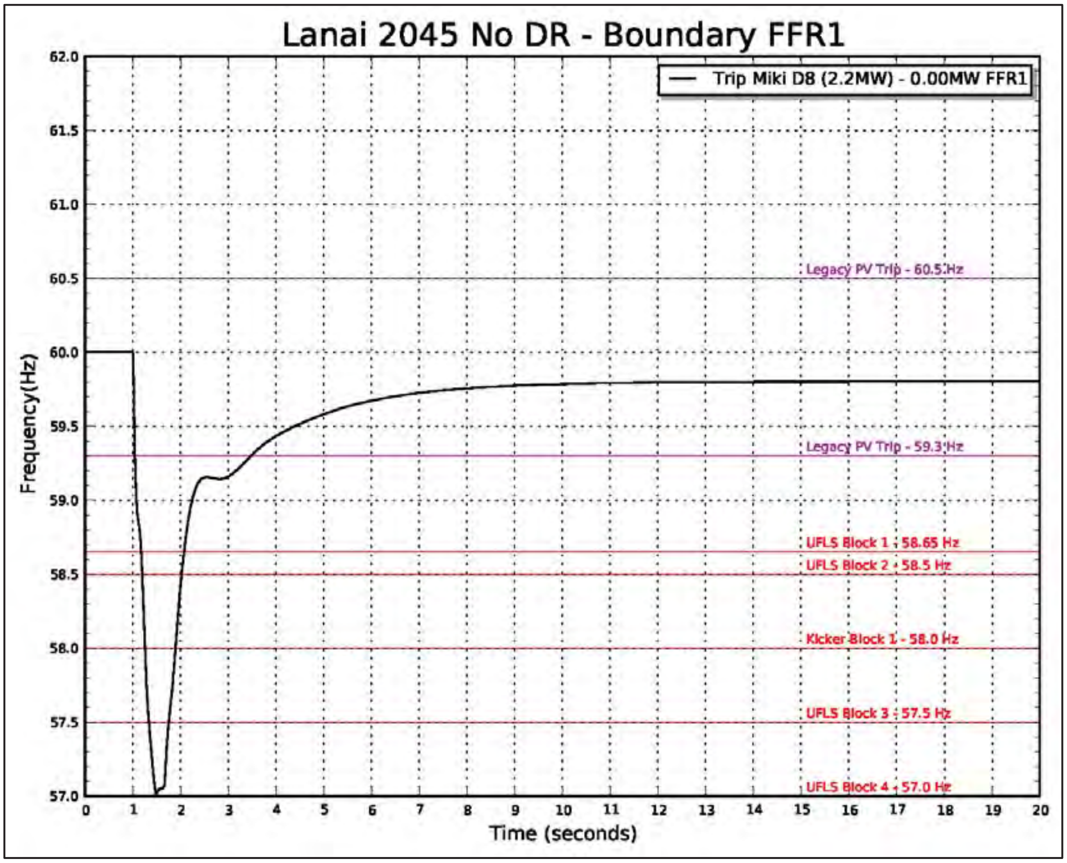

Figure O-315. Frequency Response Profile FFR1

Figure O-315 shows the frequency response profile for a Miki Basin 8 trip at 2.2 MW for a boundary hour. System kinetic energy is 6.1 MW-sec. The frequency nadir dips to 57.0 Hz and four blocks of UFLS are required to stabilize system frequency.

Lana'i Summary

The system security analysis determines technology-neutral requirements for the Post April resource plan to ensure the system is stable and maintains an acceptable stability margin. Lana'i is a nominal 12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. System security analyses includes loss of generation analysis and fault analysis for years 2019-2021. Loss of generation contingency analysis was also performed for select years beyond 2021.

Minimum Fault Current

The Lana'i distribution system requires 2.75 MVA of fault current to ensure operation of protective relay schemes. A new 2.75 MVA synchronous condenser is required in 2019 to meet minimum fault current requirements.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected to represent a boundary condition.

The system is at risk for instability in 2019. Analysis indicates 1.25 MW of FFR1 or PFR is required to stabilize system frequency for a loss of generation contingency. Table O-205 (page O-617) shows the results of the analysis

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

The system remains stable for normally cleared faults on any distribution circuit so no sensitivity analyses were performed.

MOLOKA'I SYSTEM SECURITY ANALYSIS

State of the System

Unlike Lana'i , DG-PV penetration on Moloka'i is very high so the system potentially has excess energy during the day. A 2 MW contingency BESS that is owned by HNEI has been installed but is not operational at this time.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency for day and night base case dispatches.

Unit	**Unit Ratings**					**Basecase - Palaau 7 Trip Day**			**Basecase - Palaau 7 Trip Night**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43						
PALAAU2	1.25	0.31	0.34	1.25	0.43						
PALAAU3	0.97	0.31	0.34	1.25	0.43						
PALAAU4	0.97	0.31	0.34	1.25	0.43						
PALAAU5	0.97	0.31	0.34	1.25	0.43						
PALAAU6	0.97	0.31	0.34	1.25	0.43						
PA D7	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70	2.00	0.20	1.70
PA D8	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70	2.00	0.20	1.70
PA D9	2.20	0.30	1.10	2.75	3.03						
DG-PV	3.12	0.00				1.43			0.00		
Total System MVA							5.50			5.50	
Total Kinetic Energy							6.05			6.05	
Total Load							5.43			4.00	
Total Thermal Generation							4.00			4.00	
Total Renewable Generation							1.43			0.00	
Total Generation							5.43			4.00	
Excess Generation							0.00			0.00	
Total Up Regulation							0.40			0.40	
Total Down Regulation							3.40			3.40	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.45	59.3Hz Output		0.58
	60.5Hz Capacity			2.02		60.5Hz Output		1.06	60.5Hz Output		1.64

Table O-137. Unit Commitment and Dispatch 2019

Table O-137 shows the unit commitment and dispatch schedules for the daytime and nighttime base case simulations.

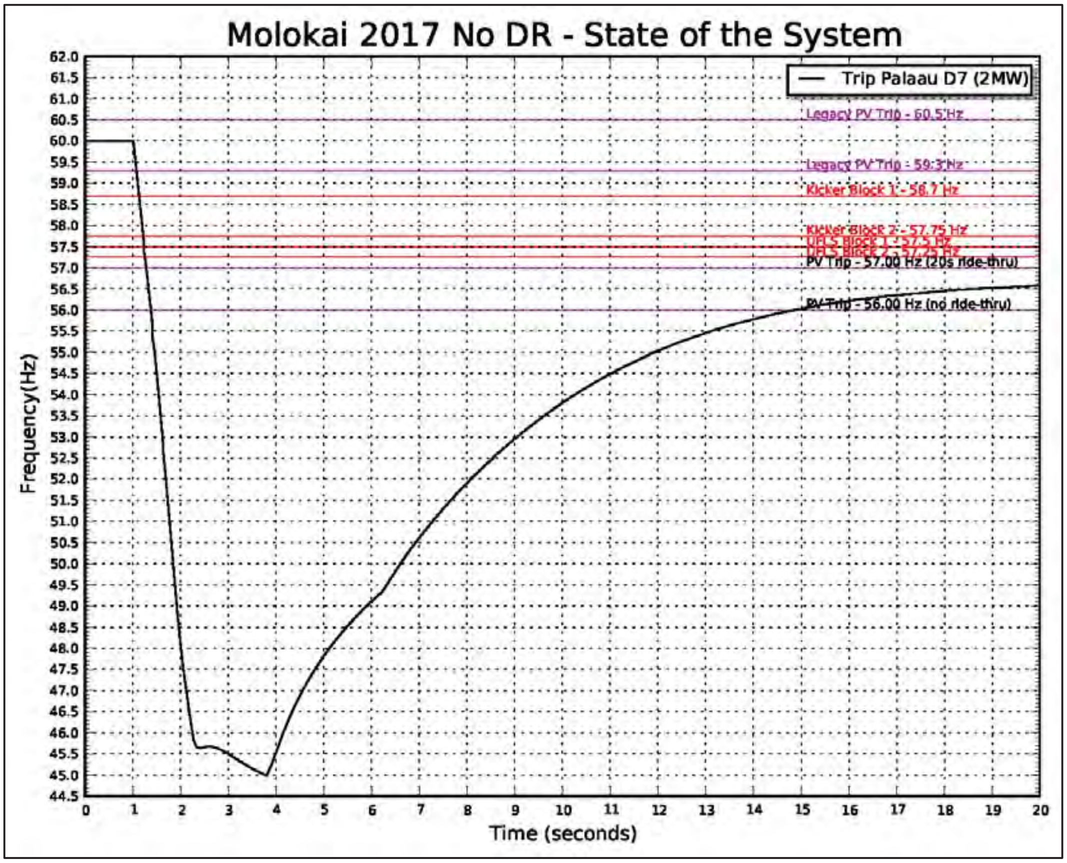

Figure O-316. Frequency Response Profile Day Base Case

Figure O-316 shows the frequency response profile for a Pala‘au 7 trip at 2.0 MW during the day. System kinetic energy is 6.1 MW-sec. The frequency breaches 45.0 Hz and two blocks of UFLS and two kicker blocks are required to stabilize system frequency.

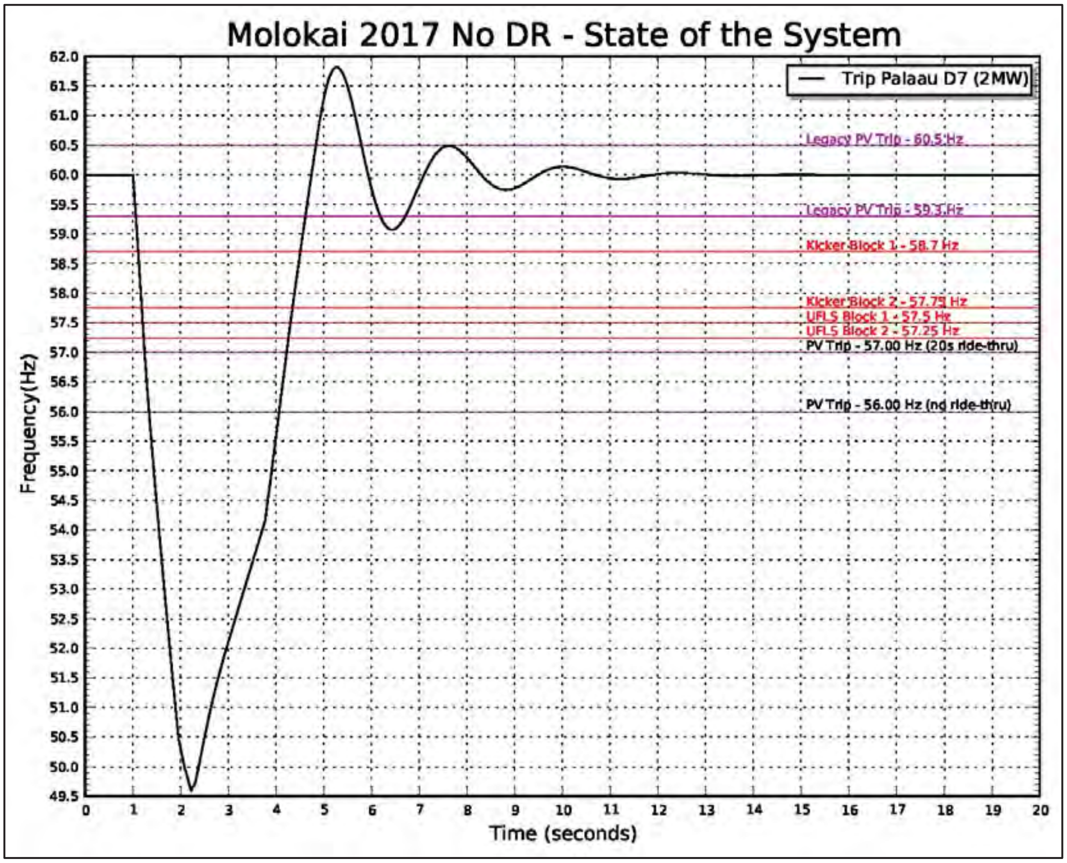

Figure O-317. Response Profile Night Base Case

Figure O-317 shows the frequency response profile for a Pala'au 7 trip at 2.0 MW during the night. System kinetic energy is 6.1 MW-sec. The frequency breaches 49.6 Hz and two blocks of UFLS are required to stabilize system frequency.

12kV Fault Simulation

Simulations were performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					Basecase - Fault Day		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70
PA D8	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70
PA D9	2.20	0.30	1.10	2.75	3.03			
DG-PV	3.12	0.00				1.43		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							5.43	
Total Thermal Generation							4.00	
Total Renewable Generation							1.43	
Total Generation							5.43	
Excess Generation							0.00	
Total Up Regulation							0.40	
Total Down Regulation							3.40	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.45
	60.5Hz Capacity			2.02		60.5Hz Output		1.06

Table O-138. Unit Commitment and Dispatch Fault Analysis 2017

Table O-138 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is1.43 MW.

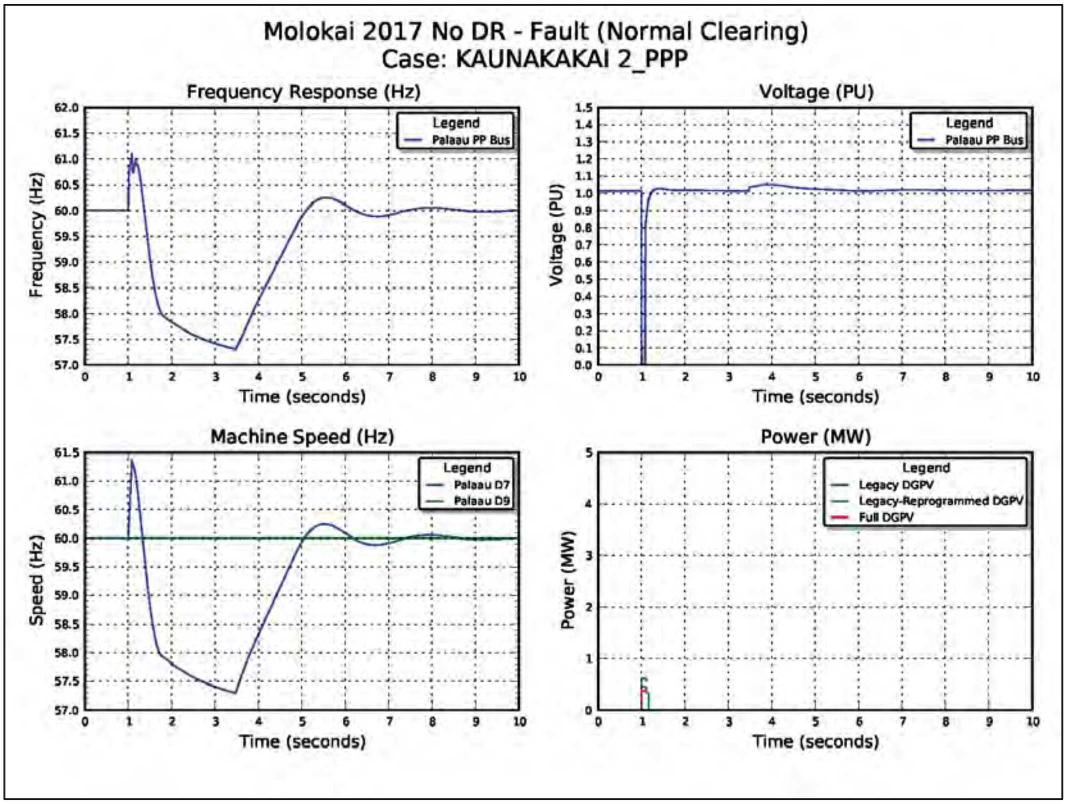

Figure O-318. System Performance Normally Cleared Fault

Figure O-318 shows the system performance for a normally cleared fault on the Kaunakakai 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.43 MW from inverter-based generation drops to zero, driving system frequency below 57.5 Hz. The system remains stable for all distribution circuit faults.

Post April DR Plan

System security analysis was performed on the Post April DR plan include loss of generation analysis and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

The Moloka'i system is a nominal 34.5/12 kV radial distribution system and does not fall under the jurisdiction of TPL-001. Distribution system reliability is driven by CAID and SAID indices as opposed to equivalent forced outage rate (EFOR). Therefore, the reliability criterion that was used for the frequency response analysis is to prevent system collapse and to maintain acceptable stability margin.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

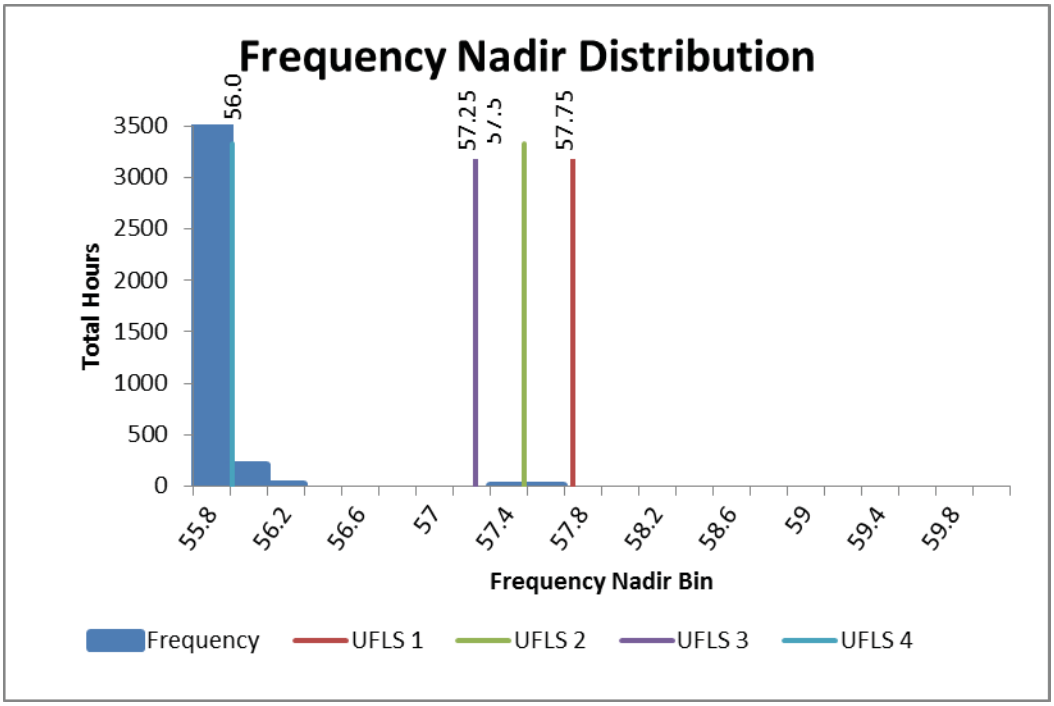

Figure O-319. Frequency Nadir Histogram 2019

Figure O-319 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 8736 hours was 4:00 PM on Saturday, March 13. The frequency nadir range for the boundary hour is > 56.0 Hz.

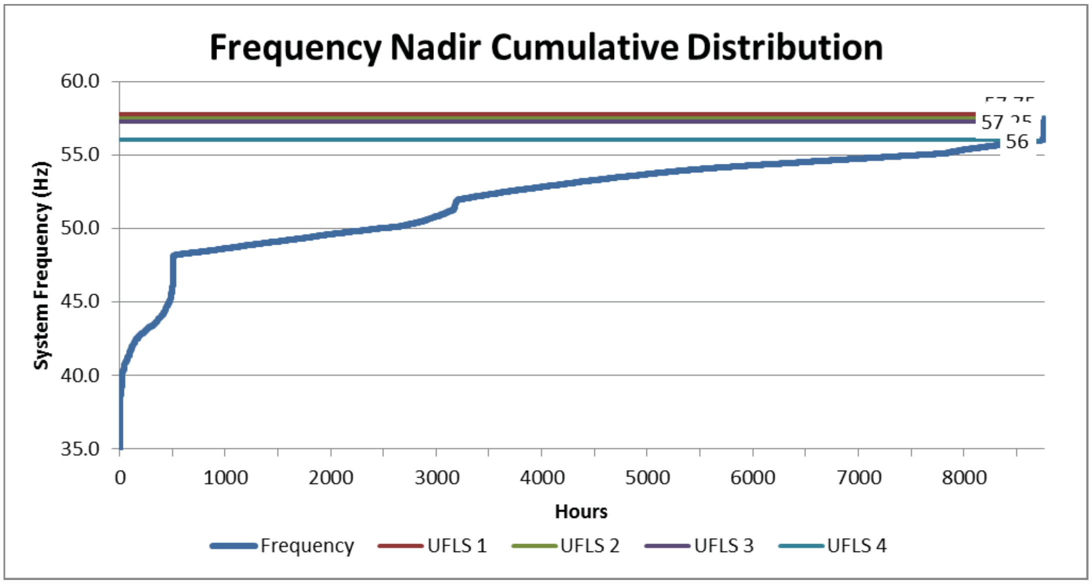

Figure O-320. Frequency Nadir Duration Curve 2019

Figure O-320 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of deploying all four blocks of UFLS for 8736 hours of the year.

Unit	Unit Ratings					**No DR - Palaau 9 Trip Boundary Mon 6/10/19 Hour 14**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.20	0.00	1.90
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	3.72	0.00				2.35		
Total System MVA						5.50		
Total Kinetic Energy						6.05		
Total Load						4.43		
Total Thermal Generation						2.20		
Total Renewable Generation						2.35		
Total Generation						4.55		
Excess Generation						0.12		
Total Up Regulation						0.00		
Total Down Regulation						1.90		
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.58
	60.5Hz Capacity			2.02		60.5Hz Output		1.64

Table O-139. Unit Commitment and Dispatch 2019

Table O-139 shows the unit commitment and dispatch for the boundary hour (6/10/19, 2:00 PM).

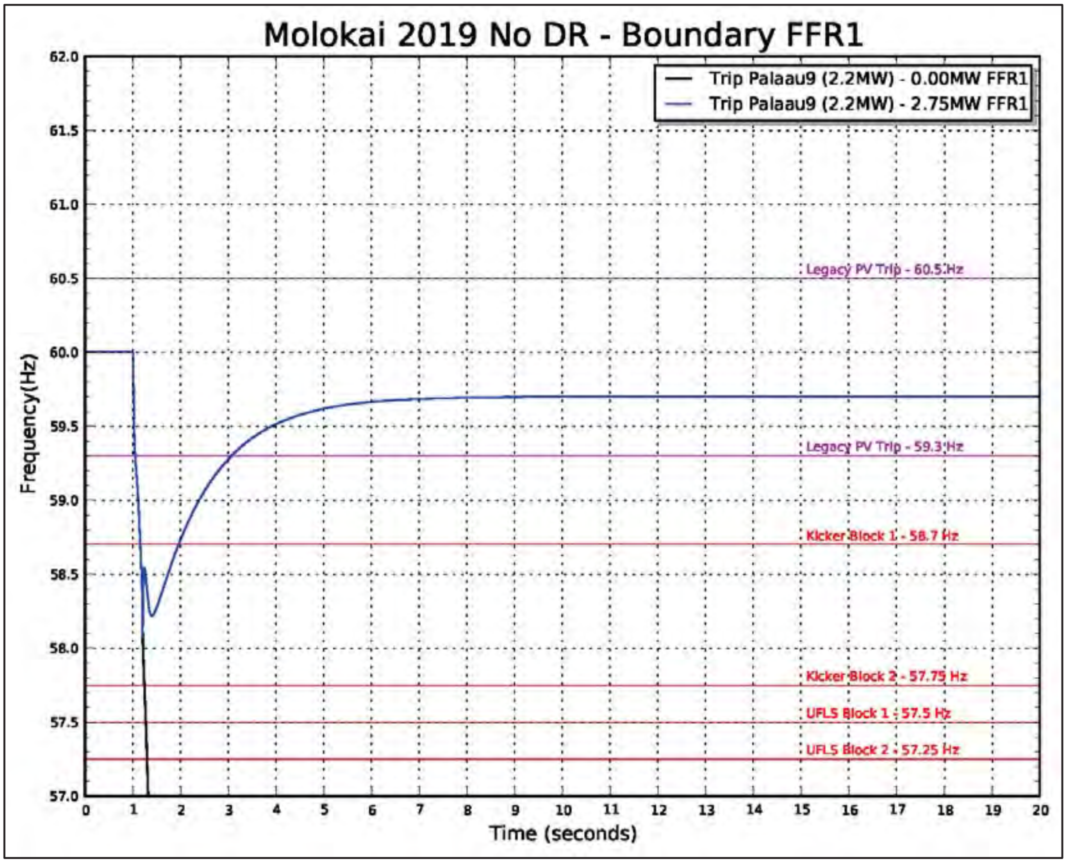

Figure O-321. Frequency Response Profile for FFR1

Figure O-321 shows the frequency response profile for a Pala'au 9 trip at 2.2 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 580 kW. With no FFR, the system collapses. The capacity of FFR1 required to stabilize system frequency is 2.75 MW.

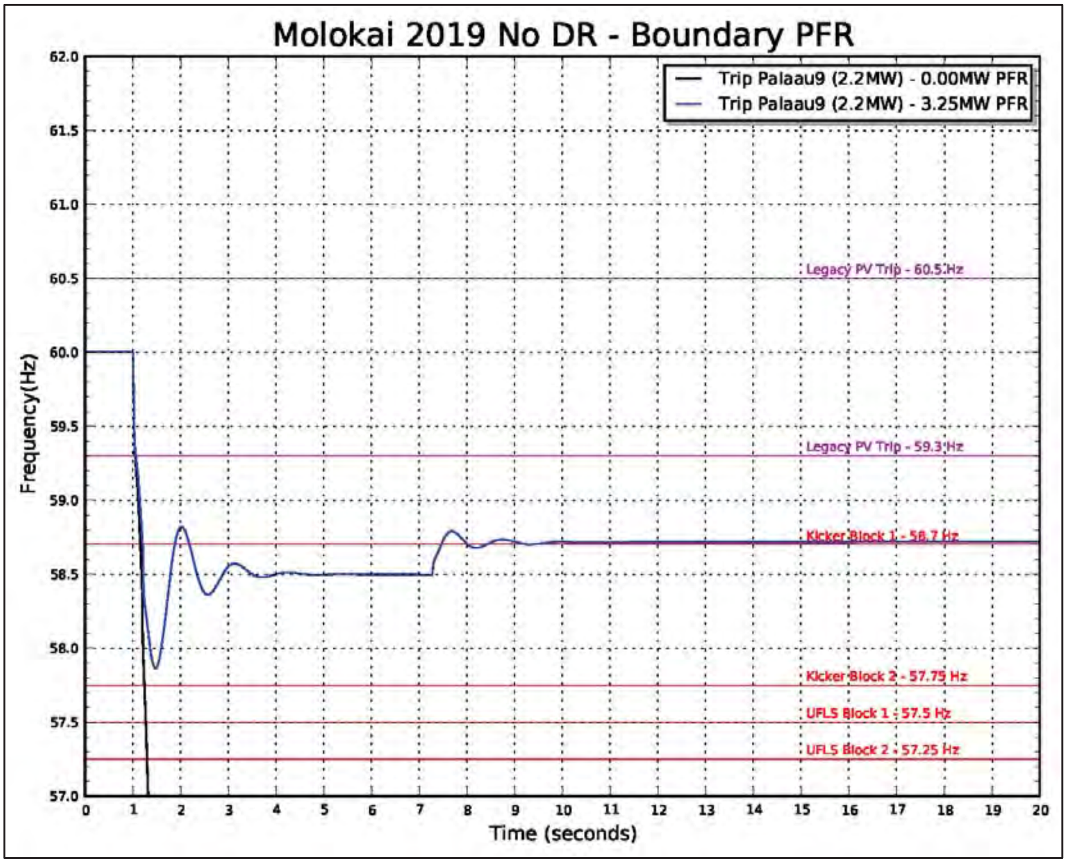

Figure O-322. Frequency Response Profile for PFR

Figure O-322 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					No DR - Fault Fri 6/21/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	1.52	0.68	1.22
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	3.72	0.00				2.53		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							4.05	
Total Thermal Generation							1.52	
Total Renewable Generation							2.53	
Total Generation							4.05	
Excess Generation							0.00	
Total Up Regulation							0.68	
Total Down Regulation							1.22	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.65
	60.5Hz Capacity			2.02		60.5Hz Output		1.86

Table O-140. Unit Commitment and Dispatch Fault Analysis 2019

Table O-140 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is 2.53 MW.

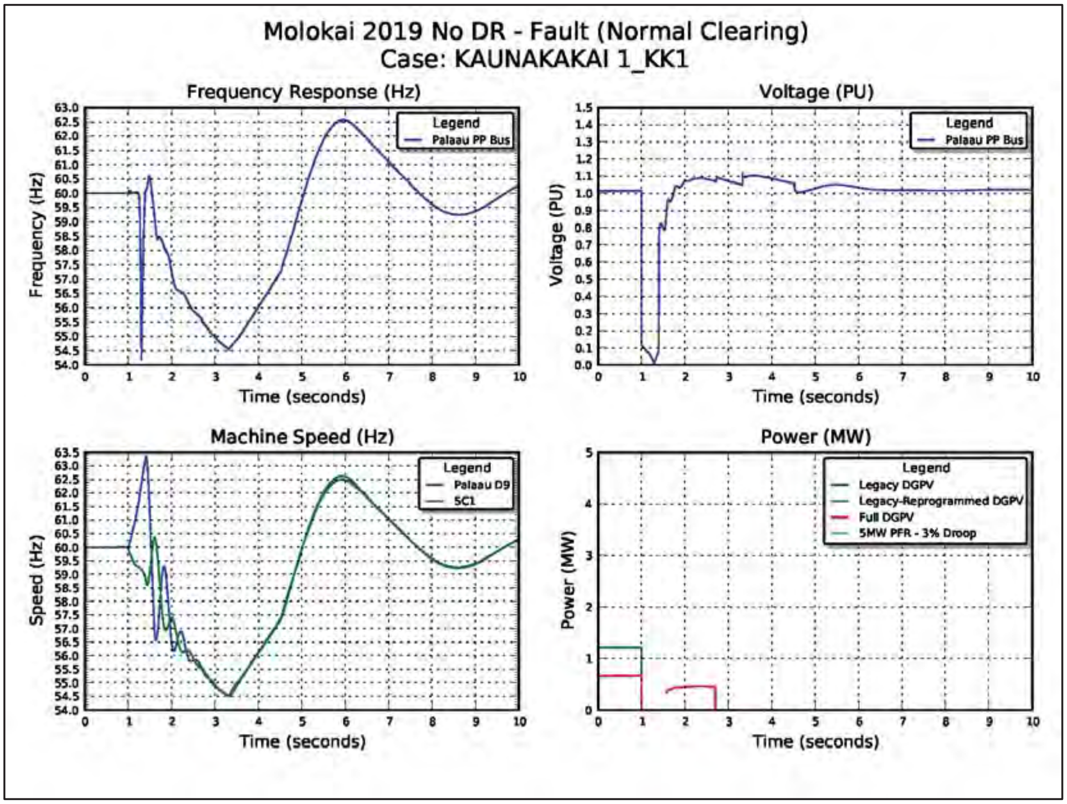

Figure O-323. System Performance Normally Cleared Fault

Figure O-323 shows the system performance for a normally cleared fault on the Kaunakakai 1 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.53 MW from inverter-based generation drops to zero, driving system frequency below 54.5.0 Hz. The system remains stable for all distribution circuit faults.

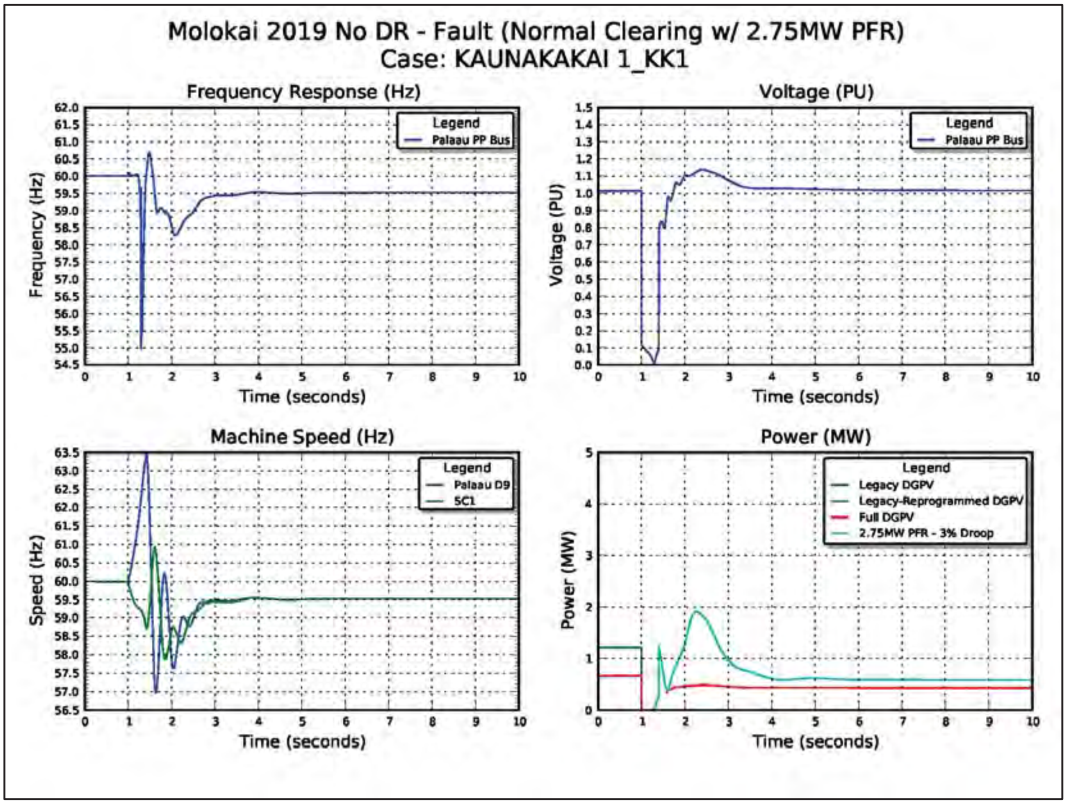

Figure O-324. Normally Cleared Fault Sensitivity PFR

Figure O-324 shows system performance with the addition of 2.75 MW PFR at 1 % droop response. For the purpose of this analysis, a BESS located at Pala'au.

The plot at the bottom right shows the frequency response from DG-PV and the 2.75 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and four blocks of UFLS stabilizes system frequency.

2020

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

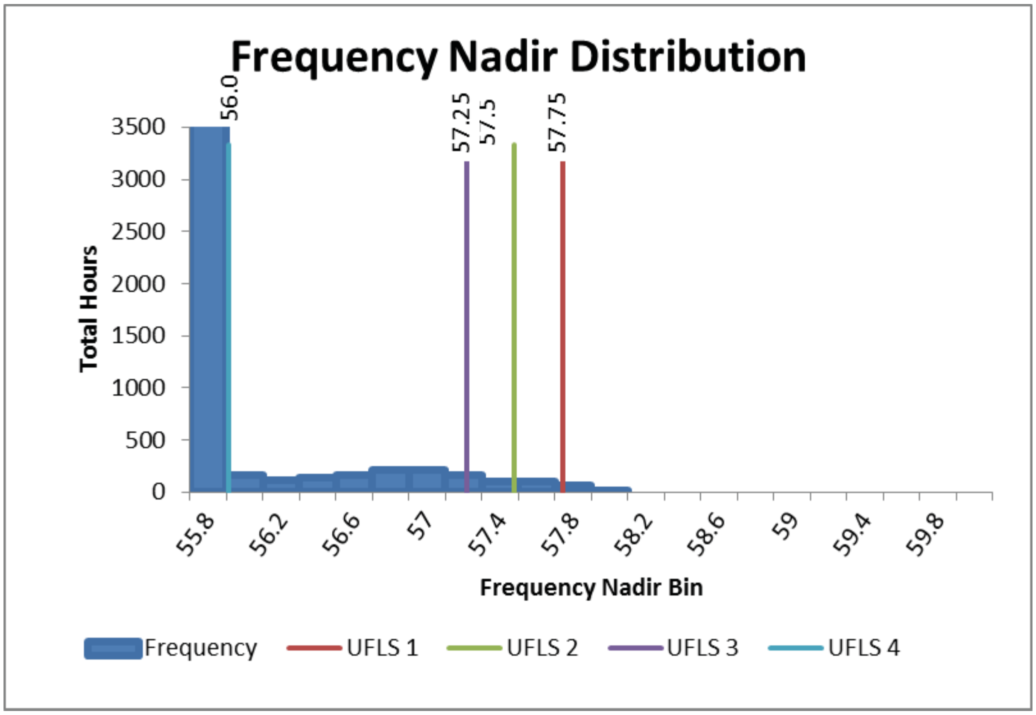

Figure O-325. Frequency Nadir Histogram

Figure O-325 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7536 hours was 4:00 PM on Friday, February 21. The frequency nadir range for the boundary hour is > 56.0 Hz.

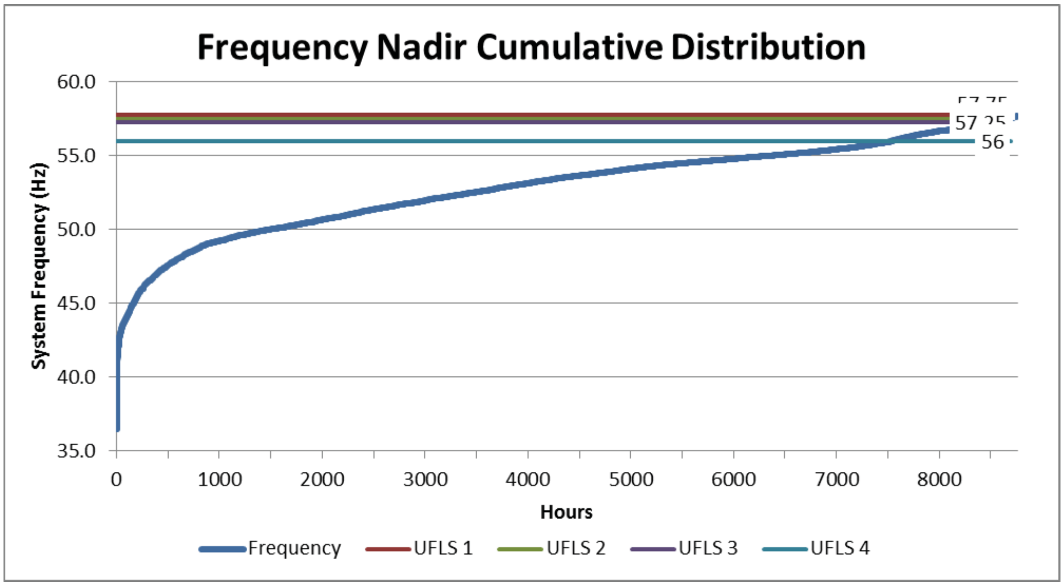

Figure O-326. Frequency Nadir Duration Curve

Figure O-326 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of deploying all four blocks of UFLS for 7536 hours of the year.

Unit	Unit Ratings					No DR - Palaau 9 Trip Boundary Fri 2/21/20 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.12	0.08	1.82
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.01		
Wind2	2.50	2.00				0.01		
DG-PV	3.94	0.00				1.34		
Total System MVA						5.50		
Total Kinetic Energy						6.05		
Total Load						3.48		
Total Thermal Generation						2.12		
Total Renewable Generation						1.36		
Total Generation						3.48		
Excess Generation						0.00		
Total Up Regulation						0.08		
Total Down Regulation						1.82		
Legacy DG-PV	59.3Hz Capacity		0.81			59.3Hz Output		0.33
	60.5Hz Capacity		2.02			60.5Hz Output		0.95

Table O-141. Unit Commitment and Dispatch 2020

Table O-141 shows the unit commitment and dispatch for the boundary hour (2/21/20, 4:00 PM).

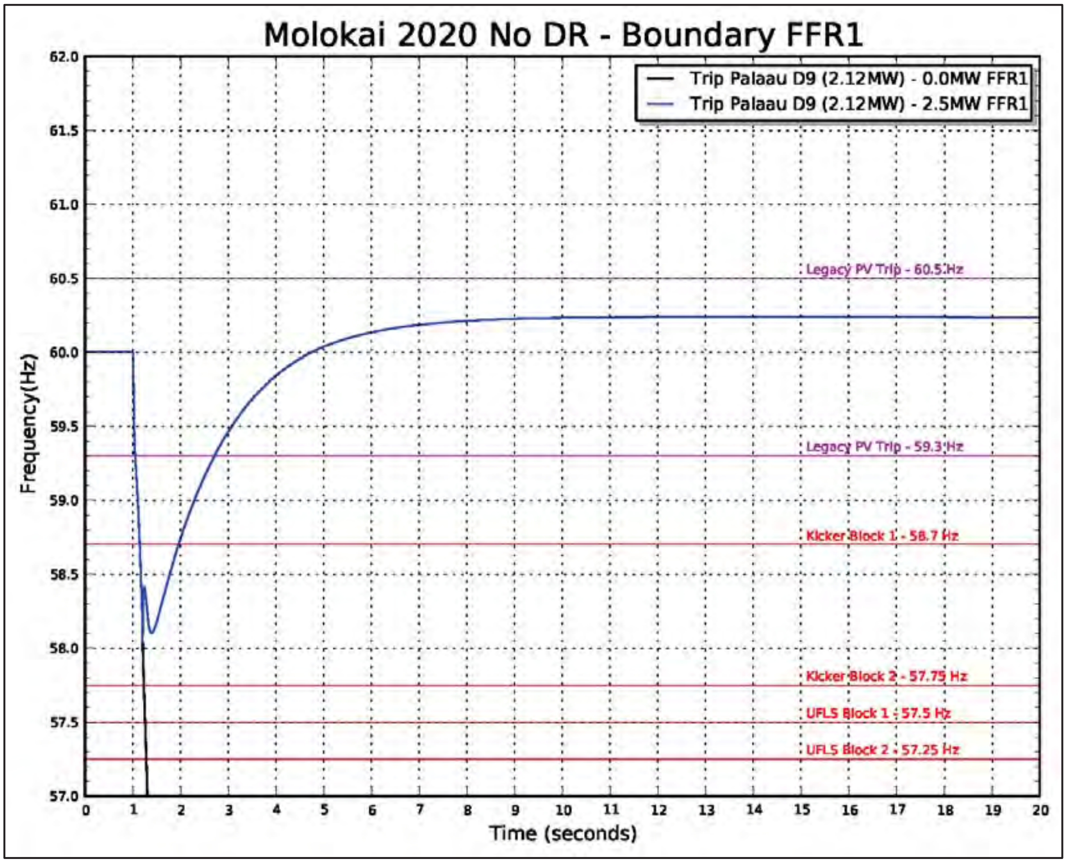

Figure O-327. Frequency Response Profile for FFR1

Figure O-327 shows the frequency response profile for a Pala'au 9 trip at 2.12 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 330 kW. With no FFR, the system collapses. The capacity of FFR1 required to stabilize system frequency is 2.5 MW.

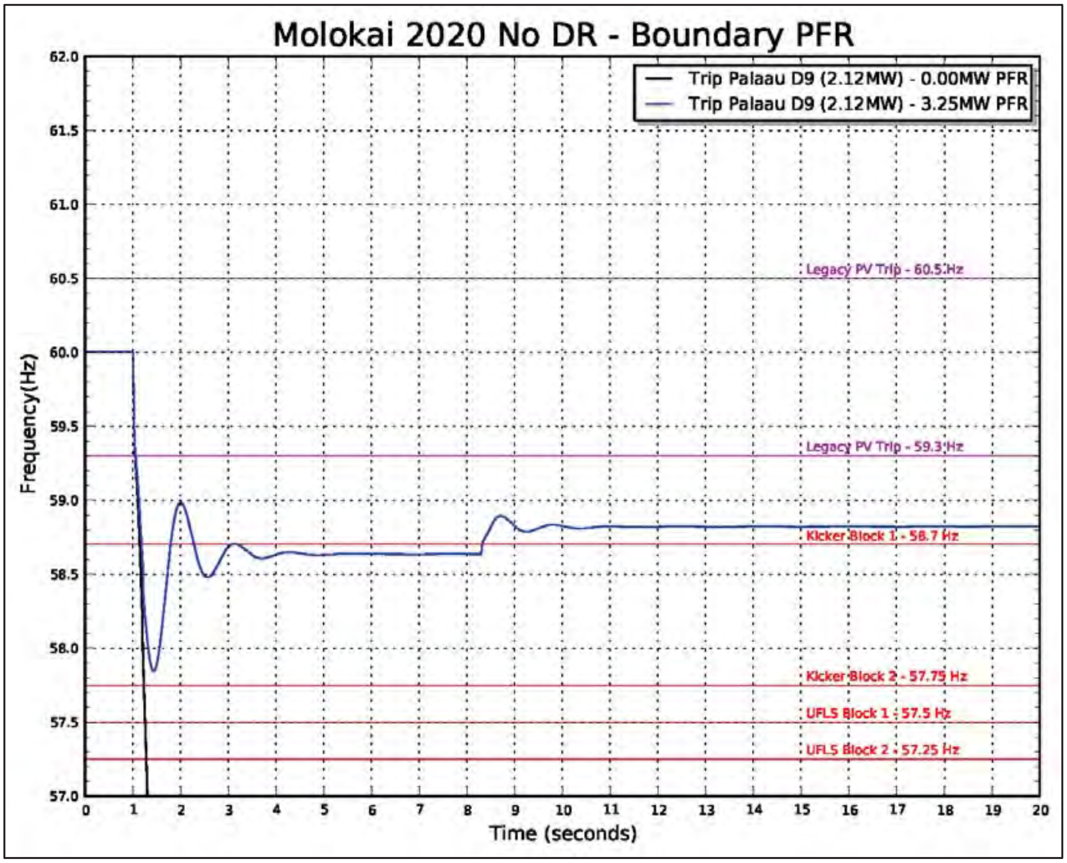

Figure O-328. Frequency Response Profile for PFR

Figure O-328 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					No DR - Fault Sun 6/21/20 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03			
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.72		
Wind2	2.50	2.00				0.72		
DG-PV	3.94	0.00				2.63		
Total System MVA						2.75		
Total Kinetic Energy						3.03		
Total Load						4.07		
Total Thermal Generation						0.00		
Total Renewable Generation						4.07		
Total Generation						4.07		
Excess Generation						0.00		
Total Up Regulation						0.00		
Total Down Regulation						0.00		
Legacy DG-PV	59.3Hz Capacity		0.81			59.3Hz Output		0.65
	60.5Hz Capacity		2.02			60.5Hz Output		1.86

Table O-142. Unit Commitment and Dispatch Fault Analysis 2020

Table O-142 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is 2.63 MW.

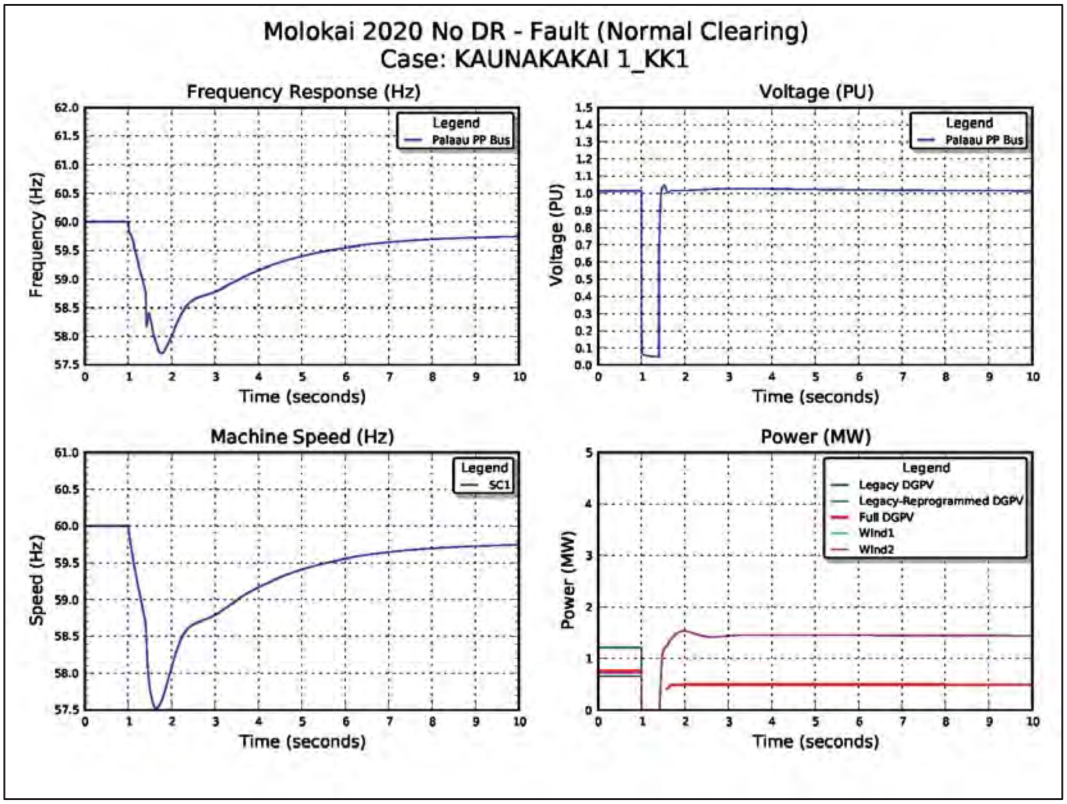

Figure O-329. System Performance Normally Cleared Fault

Figure O-329 shows the system performance for a normally cleared fault on the Kaunakakai 1 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.53 MW from inverter-based generation drops to zero, driving system frequency below 54.5.0 Hz. The system remains stable for all distribution circuit faults.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

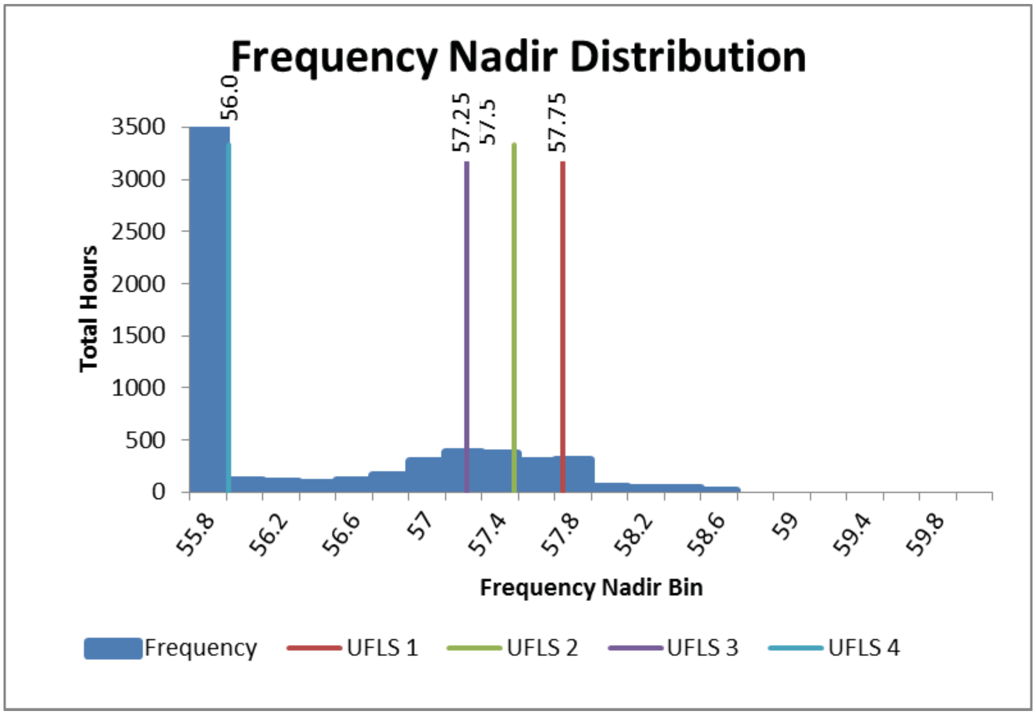

Figure O-330. Frequency Nadir Histogram 2030

Figure O-330 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 6516 hours was 3:00 PM on Tuesday, December 24. The frequency nadir range for the boundary hour is > 56.0 Hz.

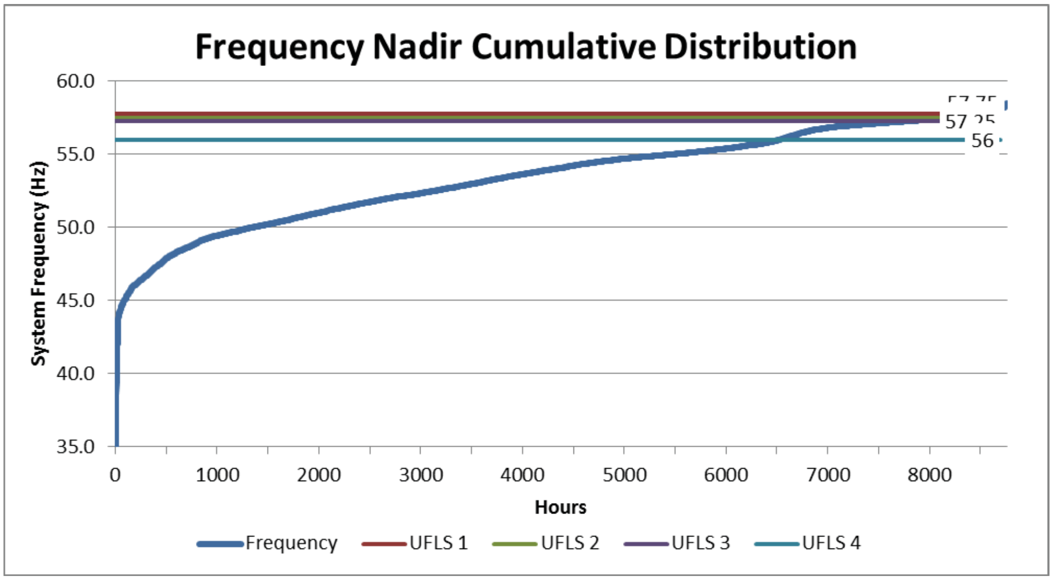

Figure O-331. Frequency Nadir Duration Curve 2030

Figure O-331 shows the frequency nadir duration curve for the resource plan in 2030. The system is at risk of deploying all four blocks of UFLS for 6516 hours of the year.

Unit	Unit Ratings					No DR - Paalau 9 Trip Boundary Tues 12/24/30 Hour 15		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.16	0.04	1.86
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.00		
Wind2	2.50	0.00				0.00		
DG-PV	6.13	0.00				1.90		
Total System MVA						5.50		
Total Kinetic Energy						6.05		
Total Load						4.05		
Total Thermal Generation						2.16		
Total Renewable Generation						1.90		
Total Generation						4.06		
Excess Generation						0.01		
Total Up Regulation						0.04		
Total Down Regulation						1.86		
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.33
	60.5Hz Capacity			2.02		60.5Hz Output		0.93

Table O-143. Unit Commitment and Dispatch 2030

Table O-143 shows the unit commitment and dispatch for the boundary hour (12/24/30, 3:00 PM).

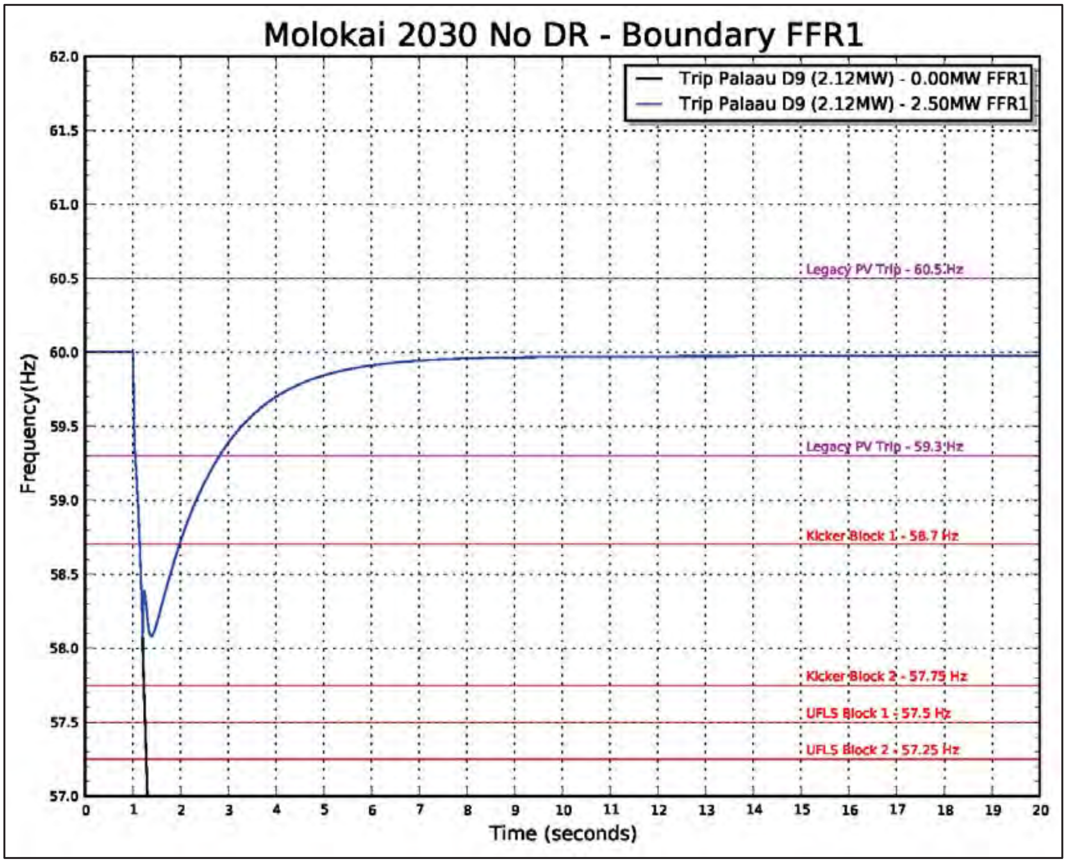

Figure O-332. Frequency Response Profile for FFR1

Figure O-332 shows the frequency response profile for Pala‘au 9 trip at 2.12 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 330 kW. With no FFR, the frequency nadir breaches 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.5 MW.

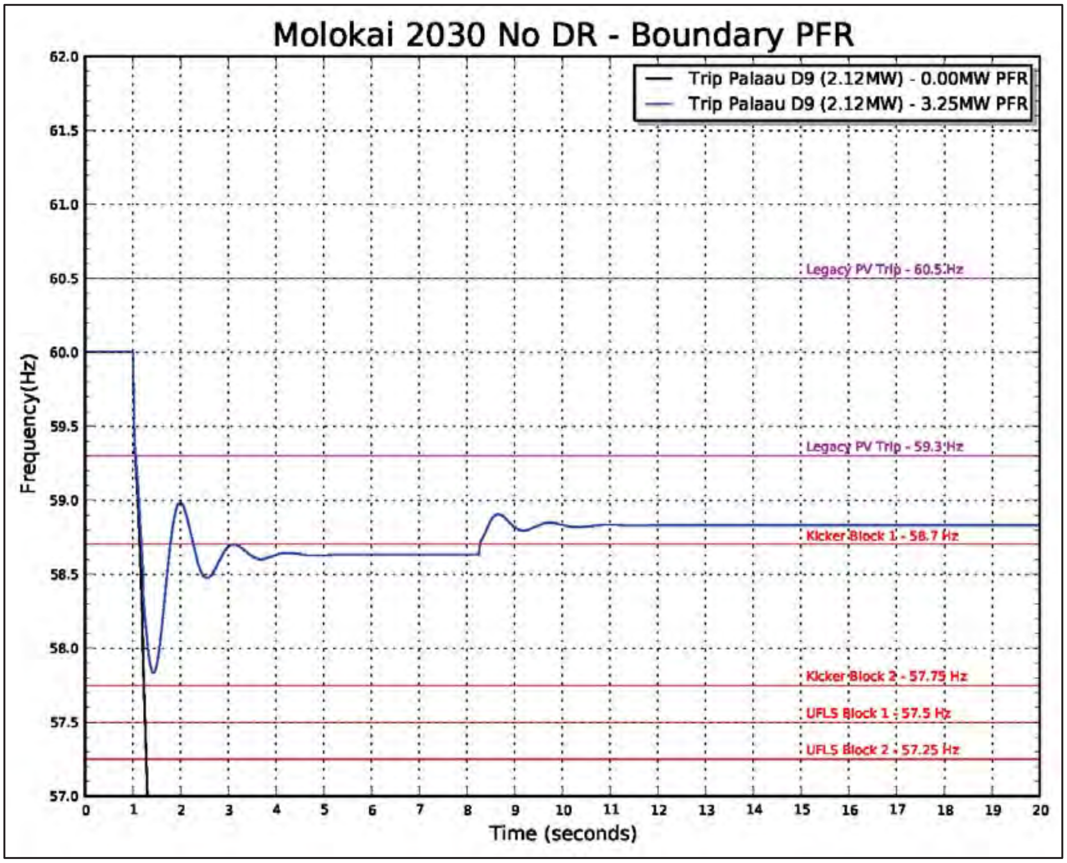

Figure O-333. Frequency Response Profile for PFR

Figure O-333 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

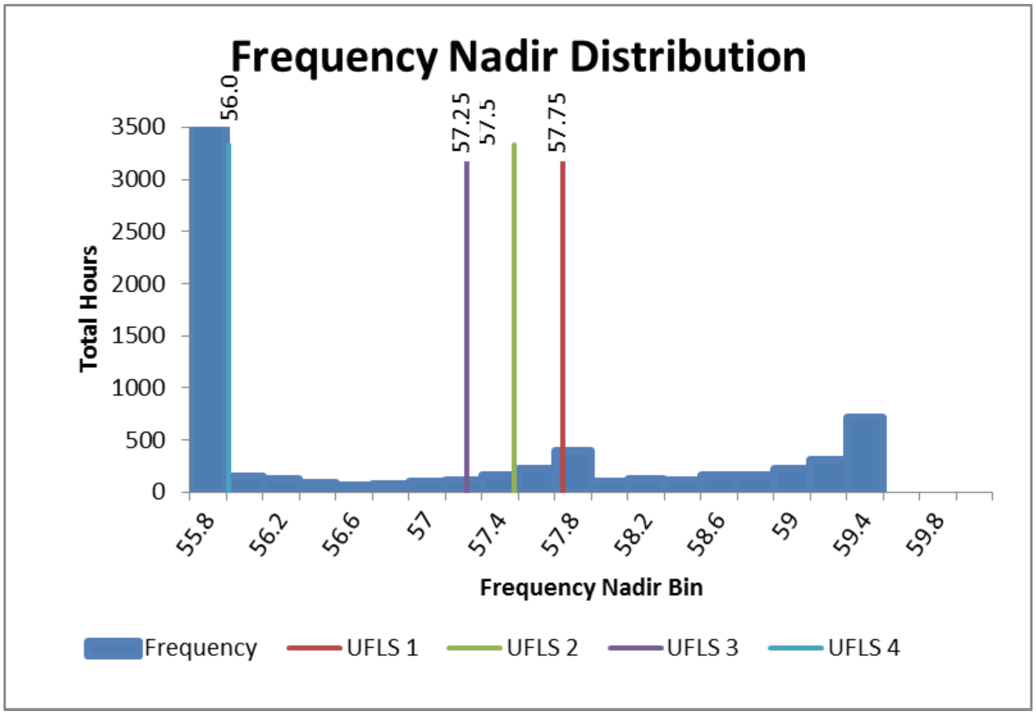

Figure O-334. Frequency Nadir Histogram 2045

Figure O-334 shows the frequency nadir histogram for the entire year. The boundary hour selected from a minimum distribution of 5509 hours was 5:00 AM on Thursday, February 16. The frequency nadir range for the boundary hour is > 56.0 Hz.

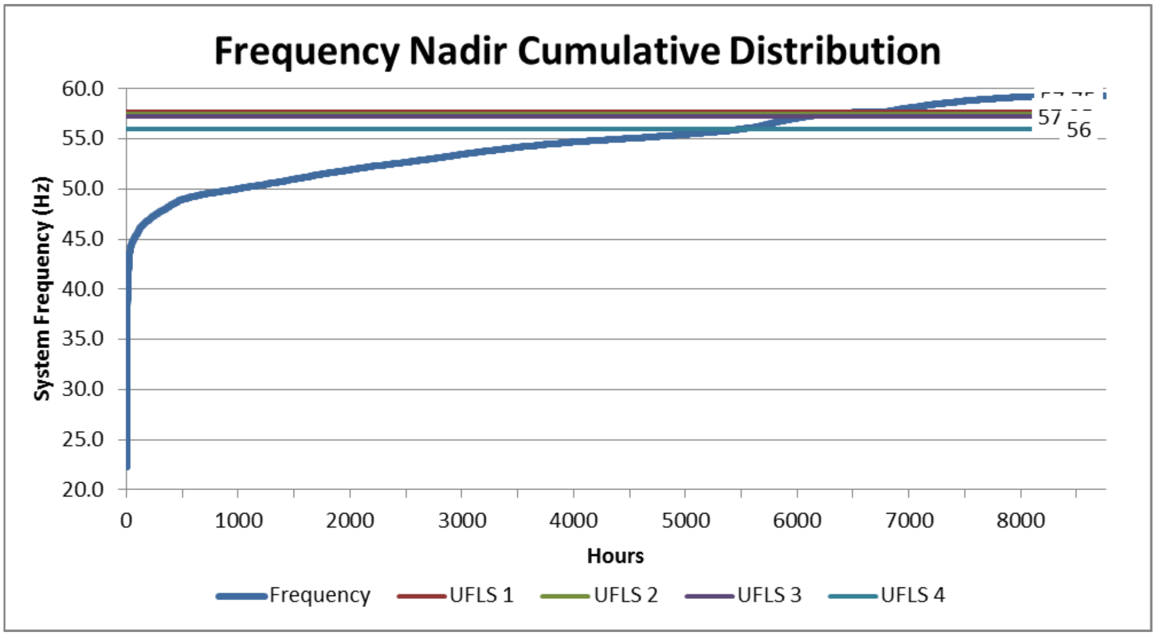

Figure O-335. Frequency Nadir Duration Curve 2045

Figure O-335 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of deploying all four blocks of UFLS for 5509 hours of the year.

Unit	Unit Ratings					No DR - Palaau 9 trip Boundary Thurs 2/16/45 Hour 5		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.12	0.08	1.82
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.00		
Wind2	2.50	0.00				0.00		
DG-PV	9.41	0.00				0.00		
Total System MVA						5.50		
Total Kinetic Energy						6.05		
Total Load						2.12		
Total Thermal Generation						2.12		
Total Renewable Generation						0.00		
Total Generation						2.12		
Excess Generation						0.00		
Total Up Regulation						0.08		
Total Down Regulation						1.82		
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.00
	60.5Hz Capacity			2.02		60.5Hz Output		0.00

Table O-144. Unit Commitment and Dispatch 2045

Table O-144 shows the unit commitment and dispatch for the boundary hour (2/16/45, 5:00 AM).

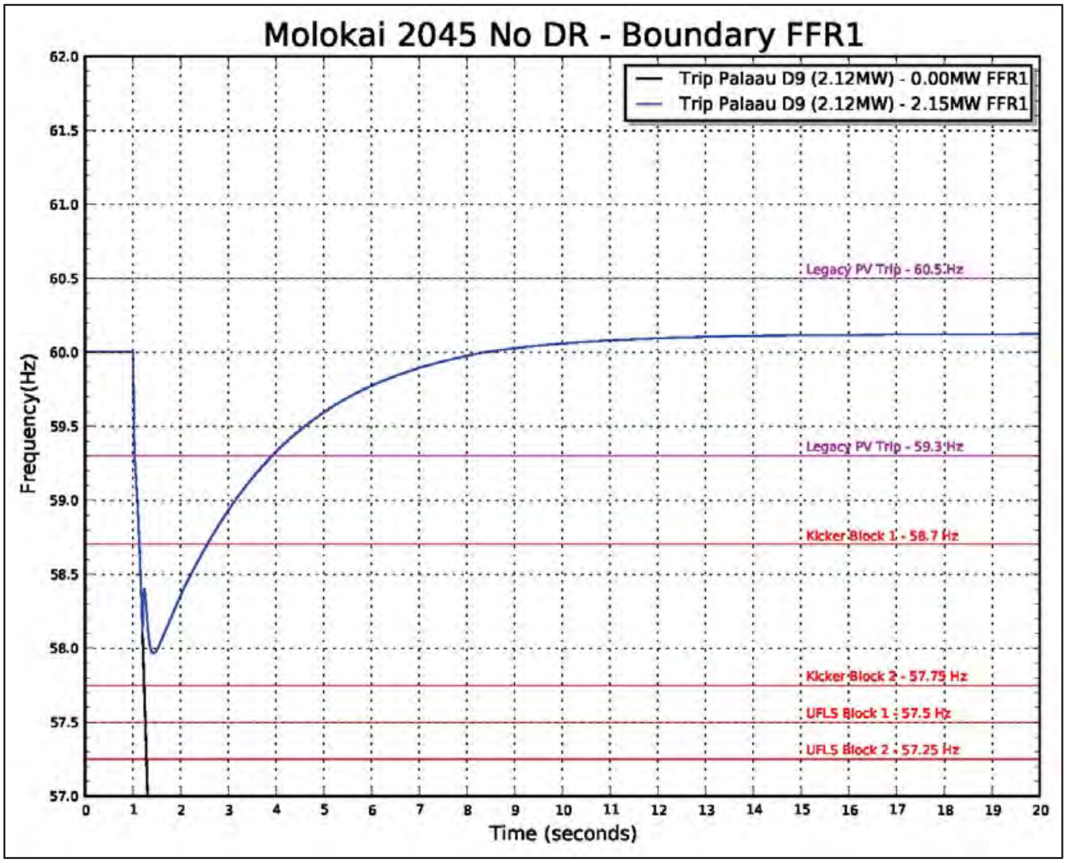

Figure O-336. Frequency Response Profile for FFR1

Figure O-336 shows the frequency response profile for a Pala‘au 9 trip at 2.12 MW for a boundary hour.. System kinetic energy is 6.1 MW-sec. The capacity of FFR1 required to stabilize system frequency is 2.15 MW.

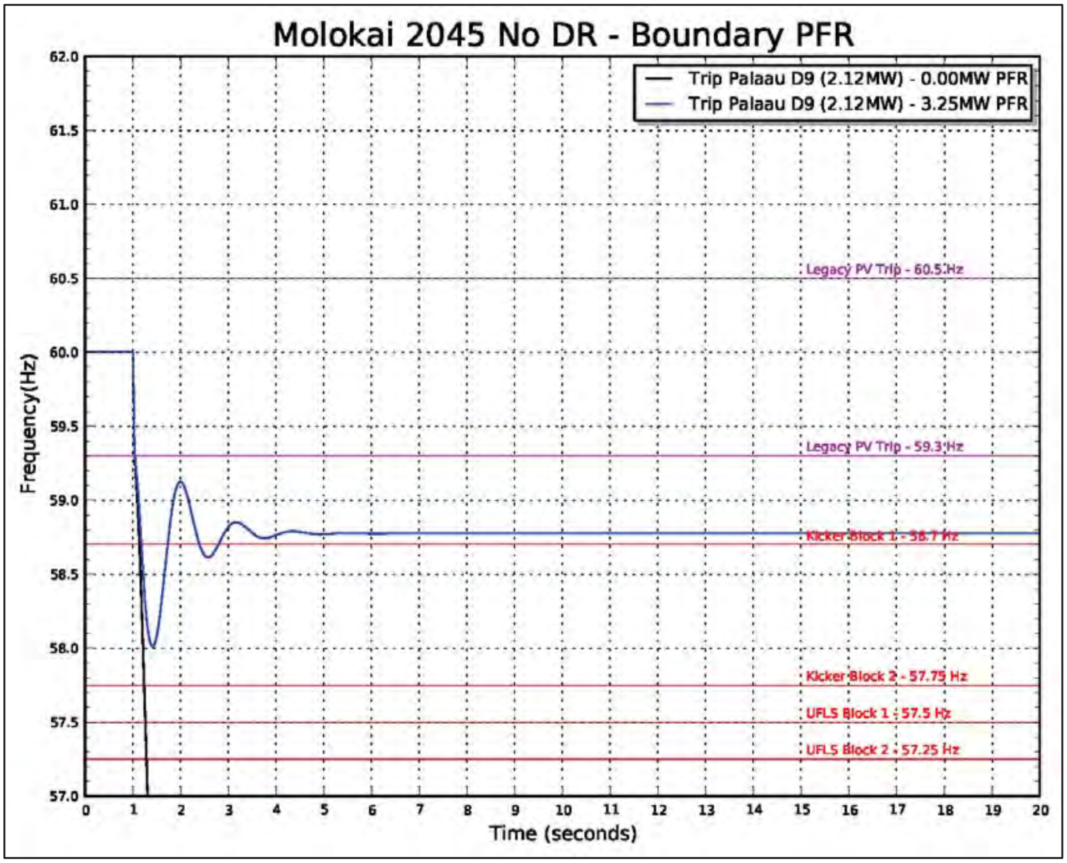

Figure O-337. Frequency Response Profile for PFR

Figure O-337 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

Moloka'i Summary

The system security analysis determines technology-neutral requirements for as single resource plan to ensure the system is stable and maintains an acceptable stability margin. Moloka'i is a nominal 34.5/12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. System security analyses includes loss of generation analysis and fault analysis for years 2019-2020. Moloka'i is scheduled to achieve 100% RPS by 2020 so loss of generation contingency analysis was also performed for select years beyond 2020.

Minimum Fault Current

The Moloka'i distribution system requires 2.75 MVA of fault current to ensure operation of protective relay schemes. A new 2.75 MVA synchronous condenser is required in 2019 to meet minimum fault current requirements.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected to represent a boundary condition. Table O-206 (page O-617) shows the results of this analysis.

The system is at risk for instability in 2019. Analysis indicates 2.75 MW of FFR1 or PFR is required to stabilize system frequency for a loss of generation contingency.

12kV Fault Analysis

Analysis was performed to determine the island-wide system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

The system remains stable for normally cleared faults on any distribution circuit so no sensitivity analyses were performed.

HAWAI‘I ISLAND SYSTEM SECURITY ANALYSIS

State of the System

The Hawai‘i system does not meet the requirement of TPL-001 for loss of generation contingency events so FFR analysis are performed for 2019.

The island of Hawai‘i has the highest penetration of renewable resources in the nation and the system often operates with the minimum must-run units for system security. In addition to the frequency stability issues that face O‘ahu and Maui, characteristics of the Hawai‘i transmission system increases the exposure to electrical faults. The Hawai‘i transmission system covers a very large territory and has approximately 640 miles of 69 kV transmission lines. In addition, most of the generation is on the east side of the island while the load center is in the west. This makes the Hawai‘i Electric Light system more susceptible to steady state and transient voltage instability.

Minimum Fault Current

A minimum fault current analysis was not performed for this PSIP. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Hawai‘i system requires 80 MVA of which 25 MVA must be connected on the West side of the island. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

Historical Contingency Events

Date/Time	Line	Type of Fault	Lowest Voltages at Keahole (A /B /C phase)	Load Loss (MW)	Frequency Peak
Sun 8/23/15 0055 hrs	7500/9300	2-Line-Gnd	0.28pu/0.26pu/0.79pu	17	60.68
Sun 8/23/15 1455 hrs	8100/8200	3-phase	0.44pu/0.46pu/0.42pu	17	60.41
Sun 8/23/15 1502 hrs	6800	3-phase	0.43pu/0.43pu/0.45pu	10	60.2
Sun 8/23/15 1541 hrs	6200	3-phase	0.45pu/0.45pu/0.45pu	14	60.28
Wed 9/2/15 1605 hrs	7100	3-phase	0.33pu/0.37pu/0.34pu	20	60.43
Thu 9/3/15 1454 hrs	8100/8200	3-phase	0.41pu/0.43pu/0.41pu	18	60.41
Sun 9/13/15 1541 hrs	7100	A-Gnd	0.61pu/0.86pu/0.61pu	5	60.17
Sun 9/13/15 1641 hrs	7100	3-phase	0.28pu/0.30pu/0.28pu	17	60.32
Tue 9/15/15 1733hrs	7500/9300	A-Gnd	0.26pu/0.68pu/0.66pu	20	60.5

Table O-145. Hawai‘i Electric Light Historic Transmission Faults

Table O-145 shows some of the more severe electrical faults on the 69 kV transmission system that illustrates the increase exposure to multi-phase electrical faults that can trigger loss of load. Therefore, fault simulations will be included in the analysis to bring the system into compliance with TPL-001.

Hawai‘i relies on under frequency load shedding for frequency response reserves for N-1 loss of generation contingency events. Hawai‘i Electric Light has implemented a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events.

Block	Setpoint (Hz)	df/dt	% System Net Demand
1	59.1	0.5 Hz/sec	5%
2	58.8	0.5 Hz/sec	10%
3	58.5	N/A	10%
4	58.2	N/A	15%
5	57.9	N/A	10%
6	57.6	N/A	20%
Kicker Block	59.3	N/A	5 MW

Table O-146. Hawai‘i Electric Light Dynamic UFLS

Table O-146 shows the capacities of the UFLS scheme. The dynamic UFLS scheme allows Blocks 1 and 2 to be initiated on df/dt settings for severe loss of generation contingency events; or by frequency set points for less severe contingencies but in most instances, the df/dt relays are activated. The dynamic UFLS scheme continuously monitors distribution circuit loads such that Blocks 1 and 2 will meet the 15% load shed requirement established by TPL-001.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

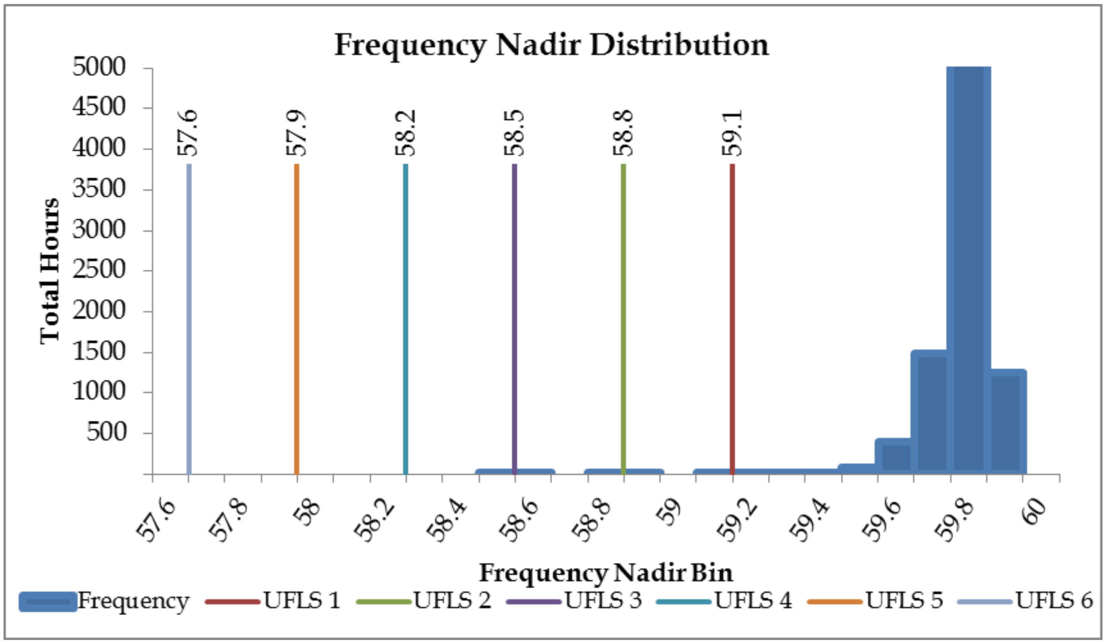

Figure O-338. Frequency Nadir Histogram 2017

Figure O-338 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 4 hours was 3:00 AM on Saturday, June 22. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

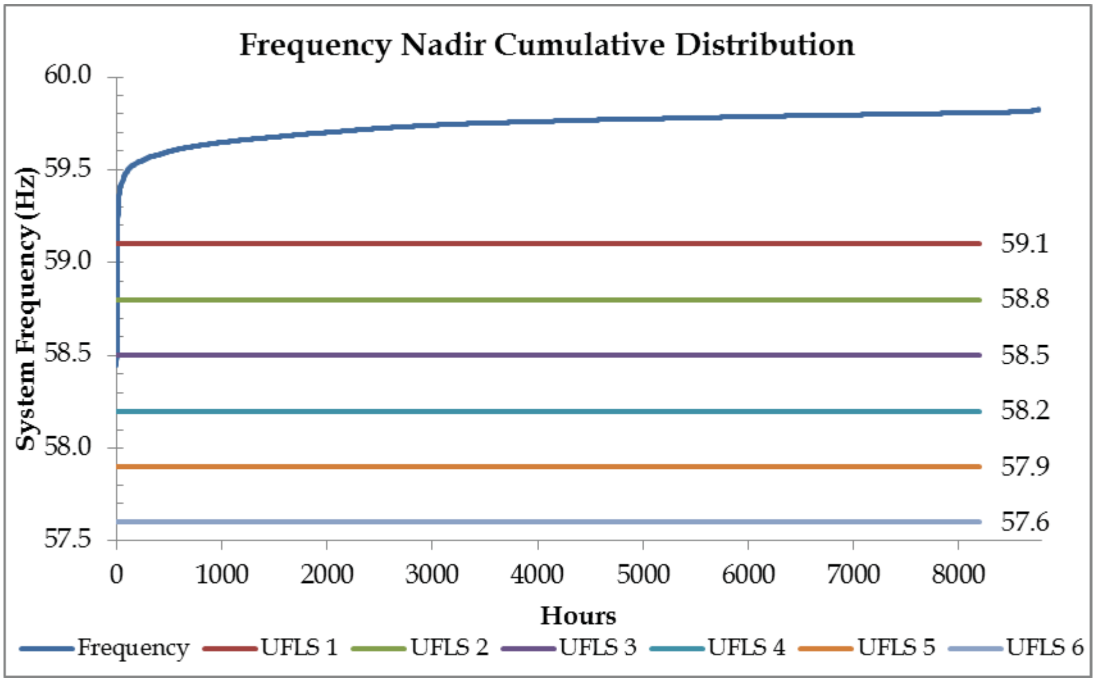

Figure O-339. Frequency Nadir Distribution Curve 2017

Figure O-339 shows the frequency nadir duration curve for the resource plan in 2017. The system is at risk of exceeding the UFLS requirements of TPL-001 for 4 hours of the year.

Unit	Unit Ratings					Theme 3 - Keahole STCC Trip Boundary Sat 6/22/19 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.9	1.1	14.9
Keahole STCC	25.0	7.0	3.13	46.5	146	24.0	1.0	17.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	12.8	0.7	7.8
Hill 6	20.5	8.0	2.53	27.5	70	19.5	1.0	11.5
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.5		
Apollo	20.5	0.0				3.1		
HRD	10.5	0.0				1.9		
Hydro	16.8	0				3		
Wind	31.0	0				5		
DG-PV	122.5	0						
Total Kinetic Energy						460		
Total Load						101		
Total Thermal Generation						93		
Total Renewable Generation						8		
Total Storage						0		
Total Generation						101		
Excess Generation						0		
Total Up Regulation						4		
Total Down Regulation						51		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-147. Unit Commitment and Dispatch

Table O-147 shows the unit commitment and dispatch schedule for the boundary hour (6/22/19, 3:00 AM).

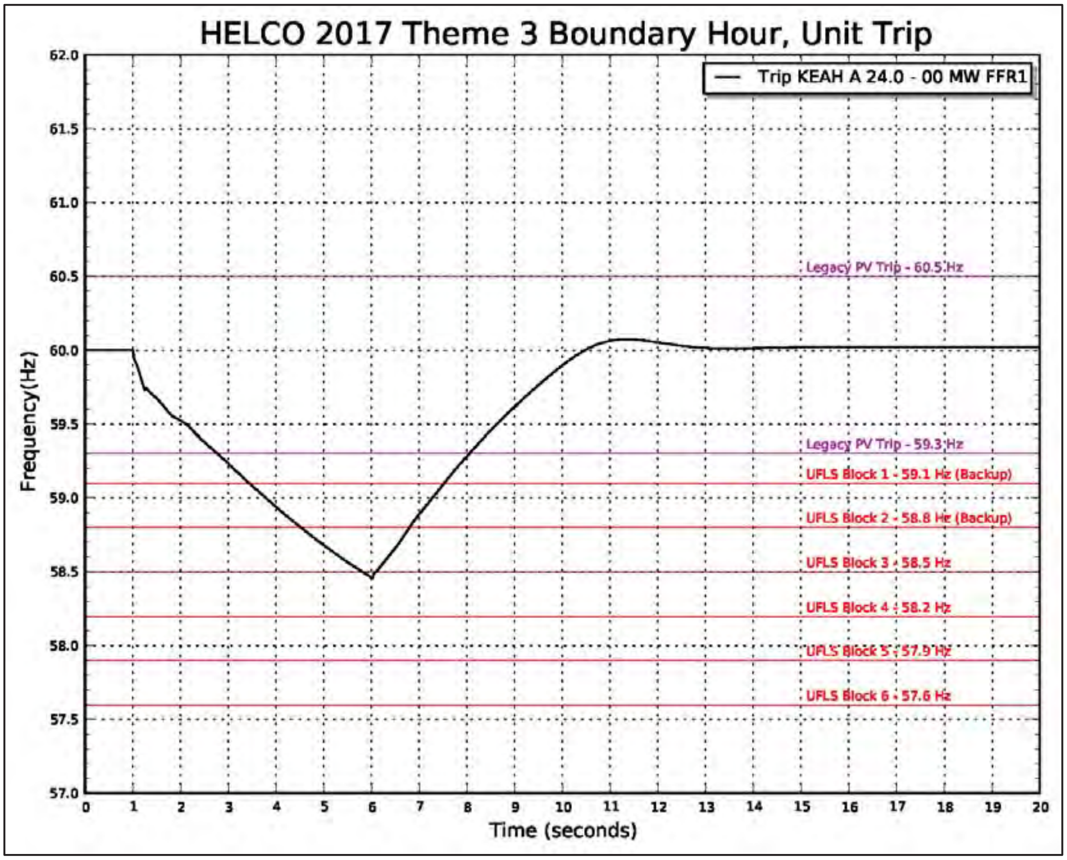

Figure O-340. Frequency Response Profile Boundary Hour

Figure O-340 shows the frequency response profile for a Keahole STCC trip at 24 MW for a boundary hour. The frequency nadir breached 58.5 Hz that requires three blocks of UFLS to stabilize system frequency. The system is not in compliance with TPL-001.

69 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 7 cycles depending on location of the fault relative to the breakers. Delayed clearing faults are modeled as a three- phase fault on the secondary bus of a tapped distribution transformer.

Unit	Unit Ratings					Theme 3 - Fault Sun 6/18/17 Hour 11		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	29.7	8.3	7.7
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	9.0	11.0	2.0
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	8.0	5.5	3.0
Hill 6	20.5	8.0	2.53	27.5	70	11.3	9.2	3.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.0		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				14.5		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				3		
Wind	31.0	0				25		
DG-PV	122.5	0				57		
Total Kinetic Energy						337		
Total Load						143		
Total Thermal Generation						58		
Total Renewable Generation						85		
Total Storage						0		
Total Generation						143		
Excess Generation						0		
Total Up Regulation						34		
Total Down Regulation						16		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.3
	60.5Hz Capacity			56.6		60.5Hz Output		30.6

Table O-148. Unit Commitment and Dispatch Fault Analysis

Table O-148 shows the unit commitment and dispatch for the 69 kV fault analysis (6/18/17, 11:00 AM). The capacity of DG-PV is 57 MW.

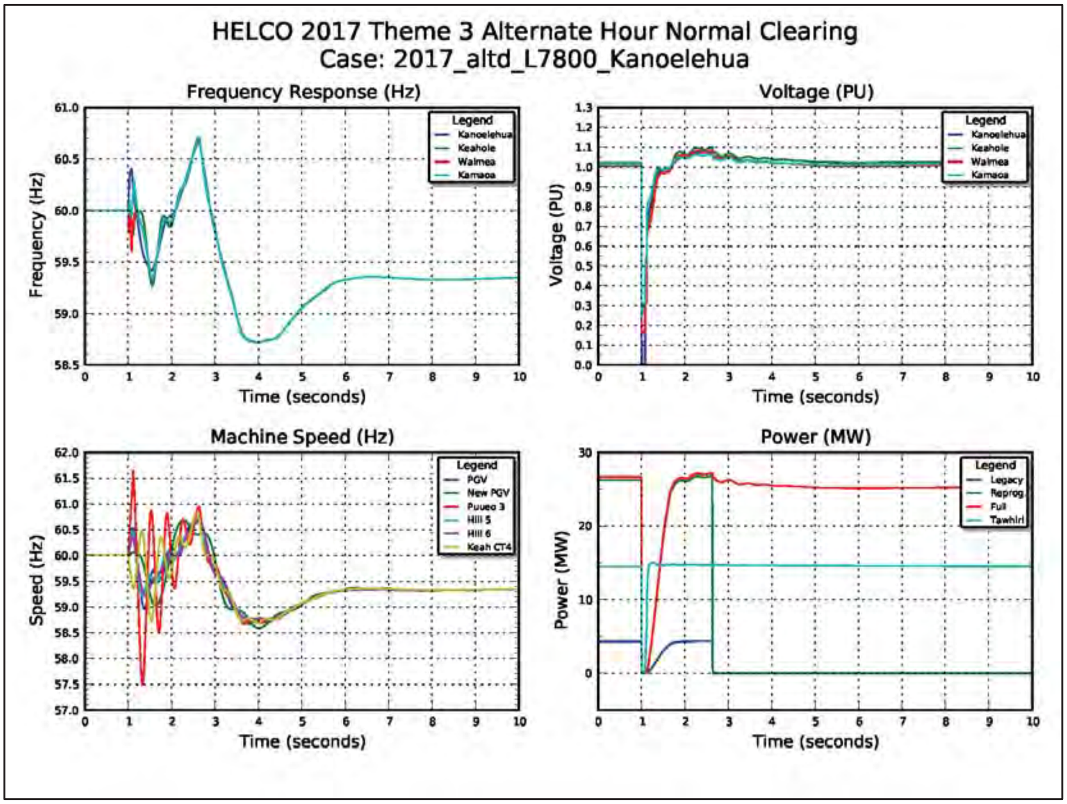

Figure O-341. System Performance for Normally Cleared Fault

Figure O-341 shows the system performance for a normally cleared fault at the Kanoelehua end of the L6400 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 57 MW from the system. System frequency initially increases but droop response from thermal units limit the initial apex to 60.4 Hz and frequency begins to decay. System voltage is restored when the fault is cleared, restoring generation from DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, and two blocks of df/dt UFLS is able to stabilize system frequency at 59.3 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping 37 MW of legacy PV. This drives system frequency to 58.8 Hz. System frequency eventually stabilizes but the margin of stability is tenuous.

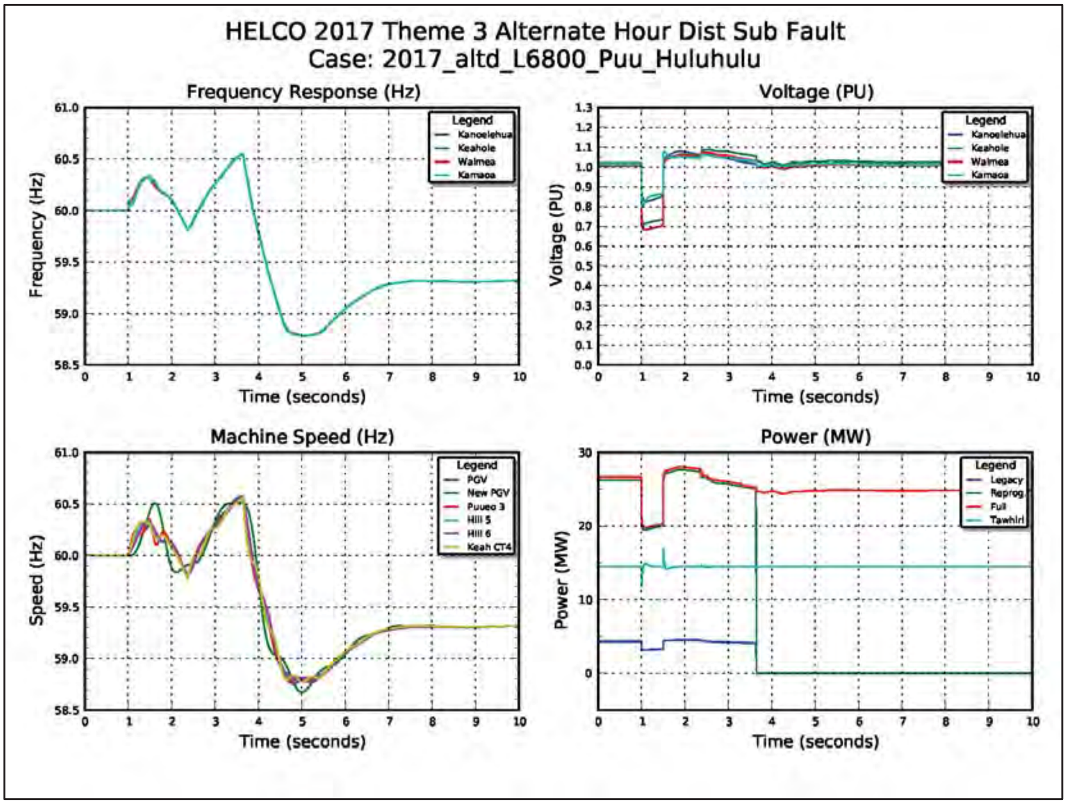

Figure O-342. System Performance for Delay Cleared Fault

Figure O-342 shows the system performance for a normally cleared fault at secondary side of the Pu‘u Huluhulu distribution transformer. System voltage is suppressed but remains above the 0.5 PU voltage ride-through threshold for inverter-based generation. There is an immediate drop in DG-PV generation because of the drop in voltage until the fault is cleared. Downward limits the initial frequency apex at 60.3 Hz but once system voltage is restored, DG-PV generation is restored to pre-fault conditions. This drives system frequency above 60.5 Hz that trips 37.4 MW of legacy PV. Frequency response from synchronous generators and two blocks of UFLS are required to stabilize system frequency at 58.7 Hz.

Post April No DR Plan - Theme 3

System security analysis performed on the Theme 3 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 3 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Hawai'i transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirement of 80 MVA on the 69 kV transmission system of which 25 MVA must be connected on the West side of the island. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai'i, the critical busses with the highest MVAR demand are the Anaeho'omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3- QV Dispatch Fri 4/19/19 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	34.2	3.8	12.2
Keahole STCC	25.0	7.0	3.13	46.5	146	22.0	3.0	15.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	33.2	26.8	14.7
Hill 5	13.5	5.0	2.20	15.6	34	12.4	1.1	7.4
Hill 6	20.5	8.0	2.53	27.5	70	19.7	0.8	11.7
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	4.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	4.5		
Apollo	20.5	0.0				20.2		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				9		
Wind	31.0	0				31		
DG-PV	122.5	0						
Total Kinetic Energy						628		
Total Load						161		
Total Thermal Generation						122		
Total Renewable Generation						39		
Total Storage						0		
Total Generation						161		
Excess Generation						0		
Total Up Regulation						35		
Total Down Regulation						61		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-149. Unit Commitment and Dispatch 2019 QV Analysis

Table O-149 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		No DR- HELCO 2019 MVAR Capability Fri 4/19/19 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	2.6	27.8	-22.1
Keahole STCC	31.6	-23.1	30.3	1.3	-53.4
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	1.2	50.7	-31.7
Hill 5	6.1	-5.5	2.8	3.3	-8.4
Hill 6	13.3	-11.4	5.0	8.3	-16.4
Puna	6.7	-6.2			
Keah CT2	15.0	-11.5			
Puna CT3	14.8	-10.6			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-6.7	11.9	-3.4
HRD	4.0	-4.0	-4.0	8.0	0.0
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			41.9		
Total Renewable MVAR Generation			-10.7		
Total Cap Bank MVAR			24.8		
Charging MVAR			16.1		
Total MVAR Supply			72.1		
Total MVAR Load			39.9		
Total MVAR Losses			32.2		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				111	
Total MVAR Absorb Capability					-135.5

Table O-150. MVAR Capability 2019 QV Analysis

Table O-150Table O-11. shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
45	L8300 Mauna Lani-Ouli
50	L8600 Kahaluu
55	L9100 Keahole-Poopoomino

Table O-151. N-1 Contingencies2019 QV Analysis

Table O-151shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

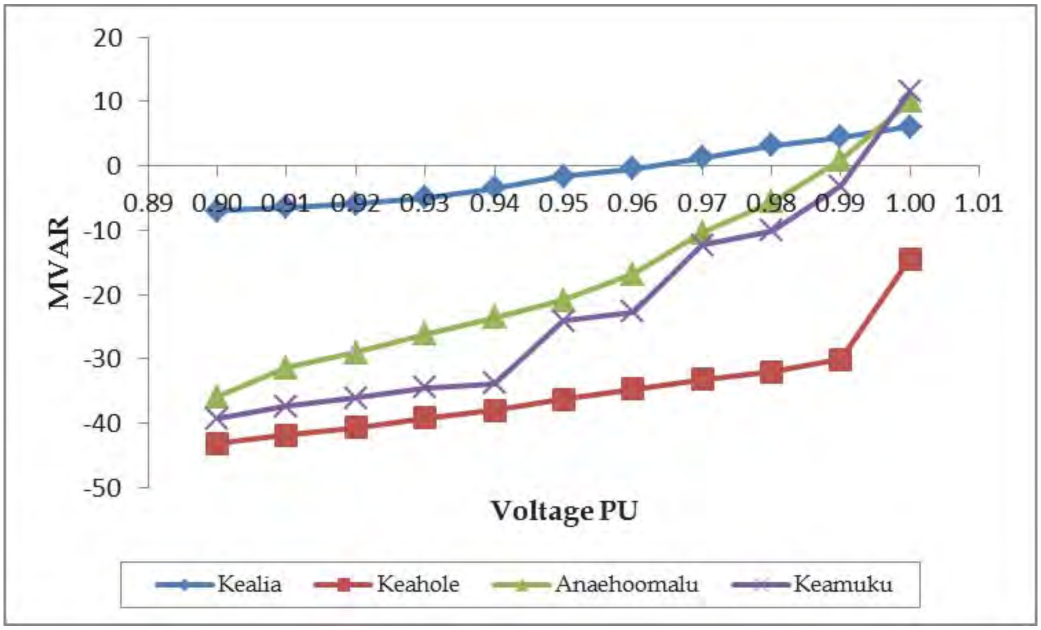

Figure O-343. QV Curves 2019

Figure O-343 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The unit commitment and dispatch meets the reactive power requirements of the system under N-1 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	6	50	4	50	3	50	1	50	0	50	-2	50	-3	50	-5	50	-6	50	-6	50	-7
8400	Keahole	37	-14	45	-30	36	-32	36	-33	36	-35	36	-36	36	-38	36	-39	36	-41	36	-42	36	-43
8500	Anaehoomalu	36	10	55	1	55	-6	45	-10	36	-17	55	-21	55	-24	55	-26	55	-29	55	-31	36	-36
8700	Keamuku	36	12	36	-3	36	-10	36	-12	36	-23	36	-24	36	-34	36	-35	36	-36	36	-37	36	-39

Table O-152. Results 2019 QV Analysis

Table O-152 shows the summary of results for the 2019 QV analysis. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

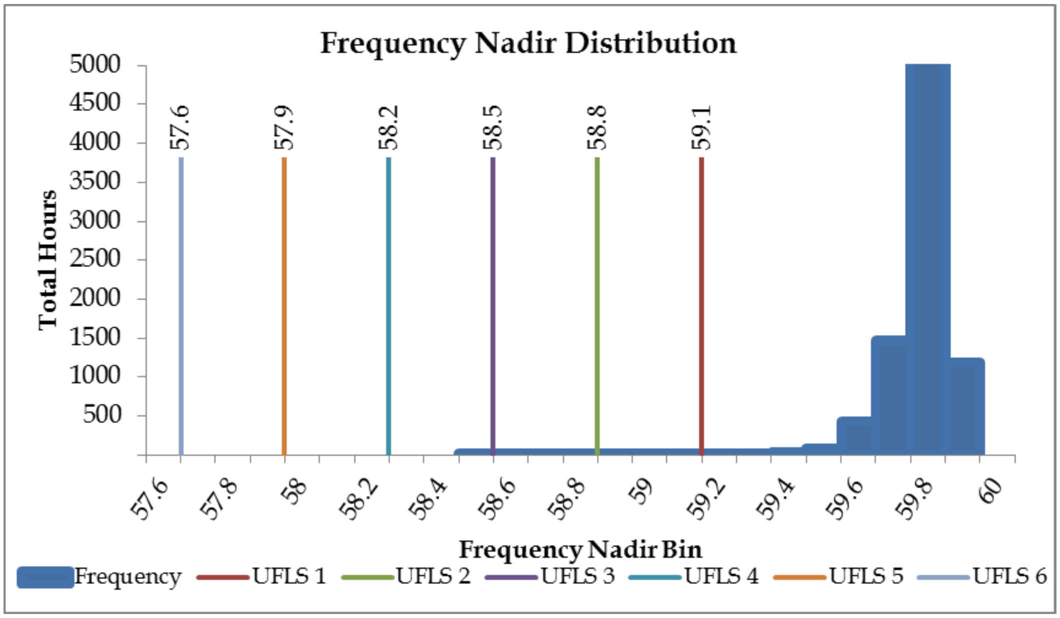

Figure O-344. Frequency Nadir Histogram for 2019

Figure O-344 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 11 hours was 3:00 AM on Saturday, June 22. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

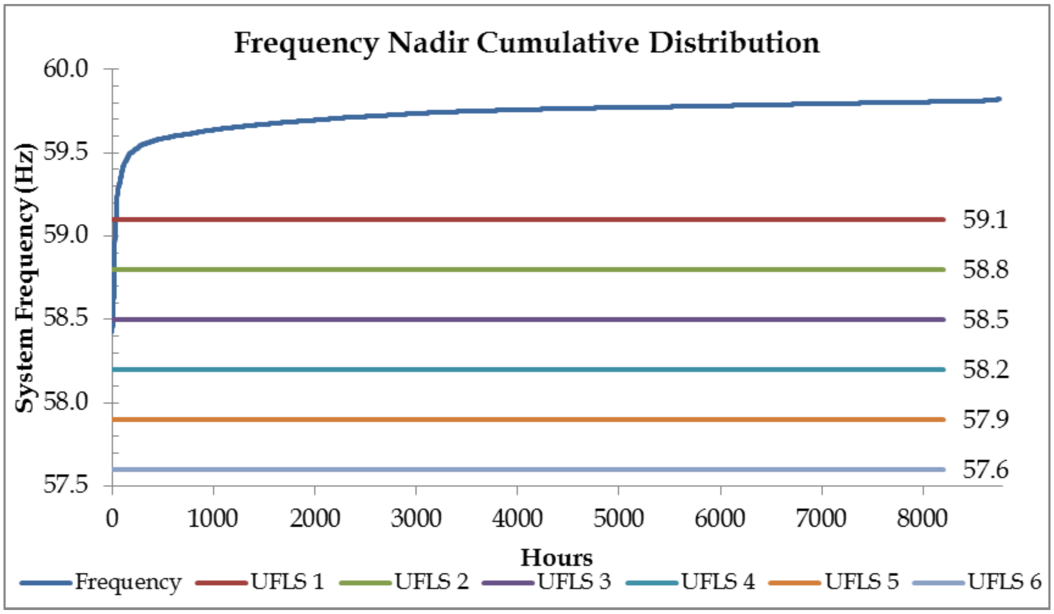

Figure O-345. Frequency Nadir Duration Curve 2019

Figure O-345 shows the frequency nadir duration curve for the Theme 3 resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 11 hours of the year.

Unit	Unit Ratings					Theme 3 - Keahole STCC Trip Boundary Sat 6/22/19 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	35.3	2.7	13.3
Keahole STCC	25.0	7.0	3.13	46.5	146	23.9	1.1	16.9
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	11.9	1.6	6.9
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	5.2		
Apollo	20.5	0.0				11.5		
HRD	10.5	0.0				3.6		
Hydro	16.8	0				9		
Wind	31.0	0				15		
DG-PV	122.5	0						
Total Kinetic Energy							390	
Total Load							95	
Total Thermal Generation							71	
Total Renewable Generation							24	
Total Storage							0	
Total Generation							95	
Excess Generation							0	
Total Up Regulation							5	
Total Down Regulation							37	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-153. Unit Commitment and Dispatch 2019

Table O-153 shows the unit commitment and dispatch for the typical hour (6/22/2019, 3:00 AM).

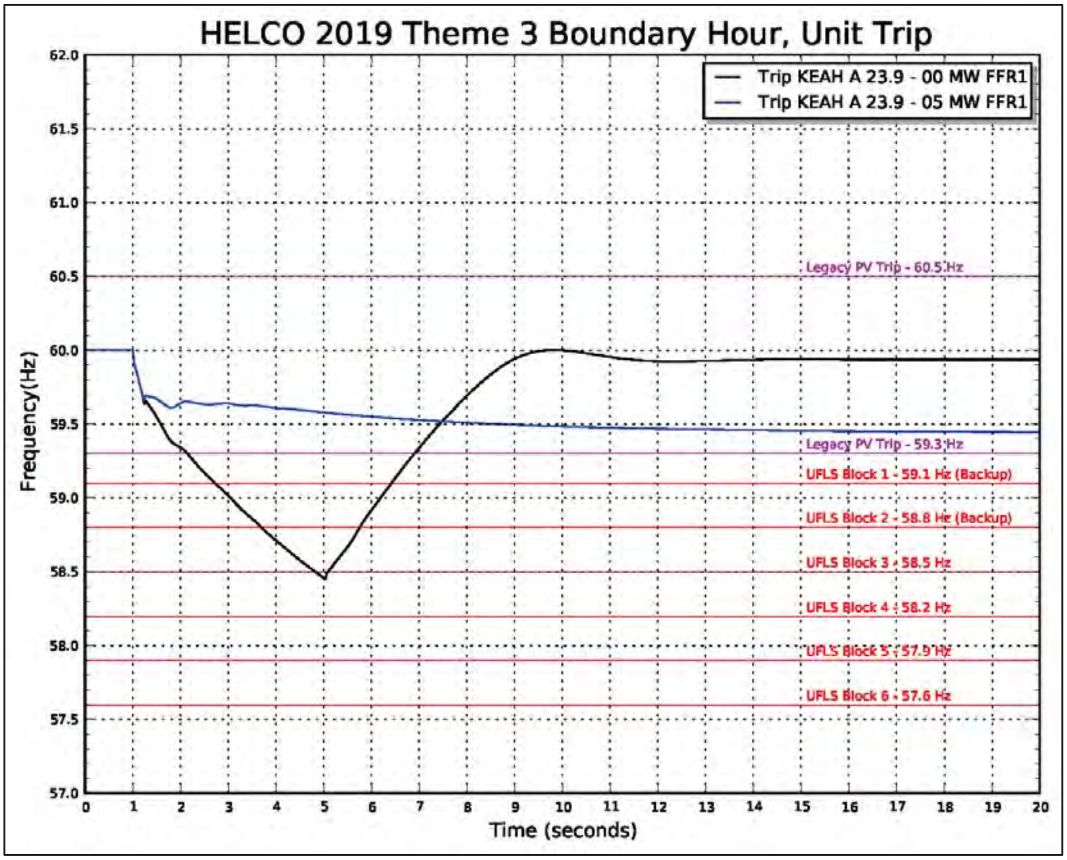

Figure O-346. Frequency Response Profile for FFR1 Boundary Hour

Figure O-346 shows the frequency response profile for a Keahole STCC trip at 24 MW. System kinetic energy is 390 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 3 MW.

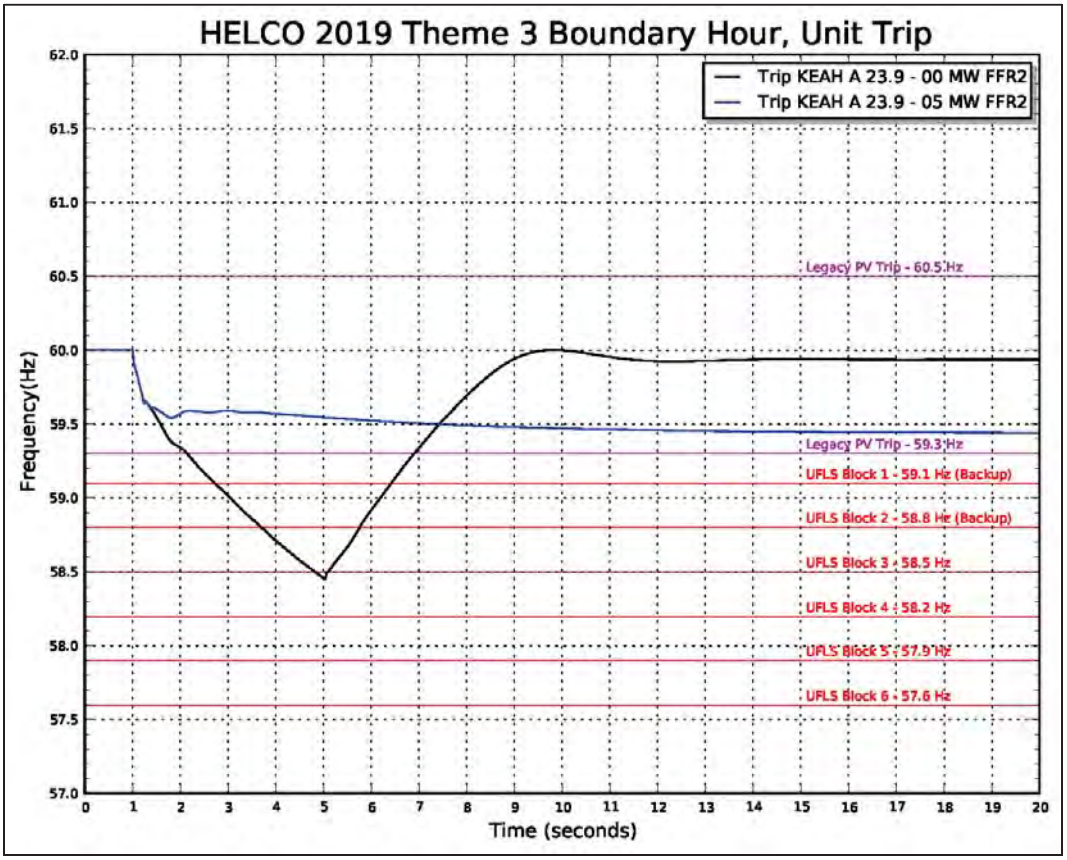

Figure O-347. Frequency Response Profile for FFR2 Typical Hour

Figure O-347 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 3 MW.

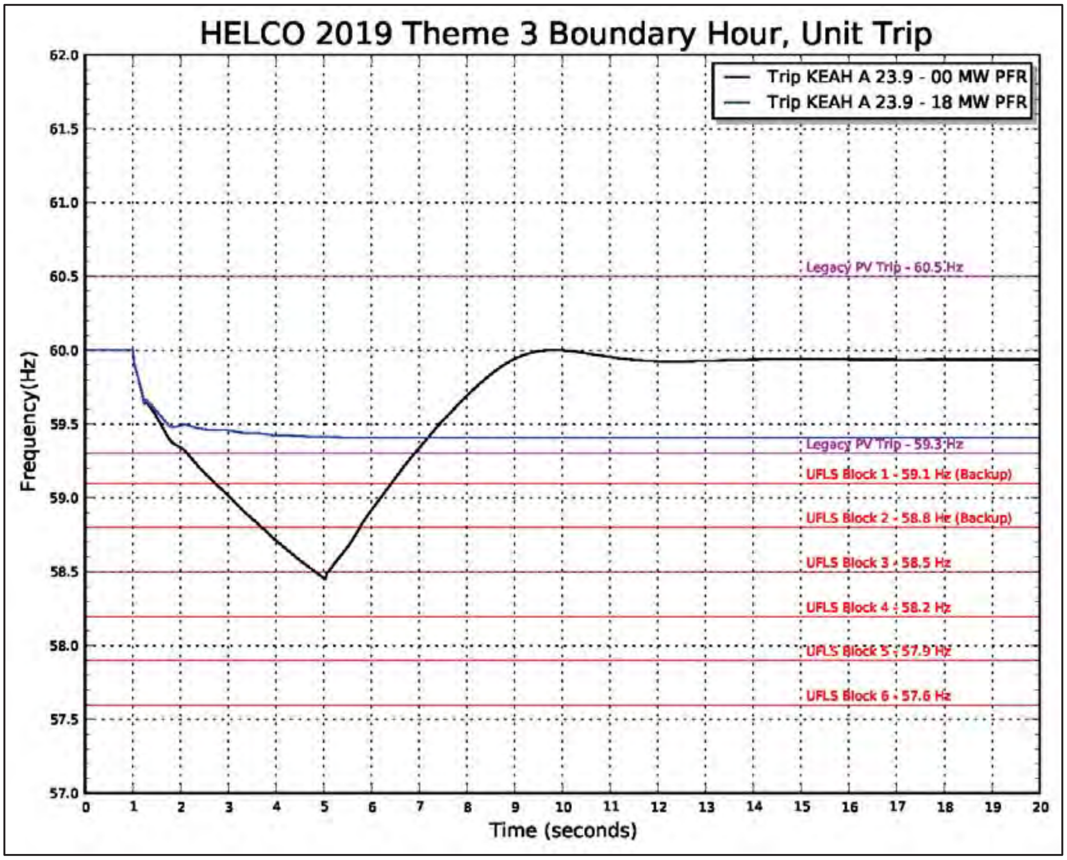

Figure O-348. Frequency Response Profile for PFR Typical Hour

Figure O-348 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 4 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 7 cycles depending on location of the fault relative to the breakers. Delayed clearing faults are modeled as a three-phase fault on the secondary bus of a tapped distribution transformer.

Unit	Unit Ratings					Theme 3 - Fault Sun 2/10/19 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146	11.8	13.2	4.8
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	10.0	3.5	5.0
Hill 6	20.5	8.0	2.53	27.5	70	17.2	3.3	9.2
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	2.1		
Apollo	20.5	0.0				20.3		
HRD	10.5	0.0				4.7		
Hydro	16.8	0				4		
Wind	31.0	0				25		
DG-PV	122.5	0				81		
Total Kinetic Energy						286		
Total Load						149		
Total Thermal Generation						39		
Total Renewable Generation						110		
Total Storage						0		
Total Generation						149		
Excess Generation						0		
Total Up Regulation						20		
Total Down Regulation						19		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		5.2
	60.5Hz Capacity			56.6		60.5Hz Output		37.4

Table O-154. Unit Commitment and Dispatch Fault Analysis

Table O-154 shows the unit commitment and dispatch for the 69 kV fault analysis (2/10/19, 12:00 PM).

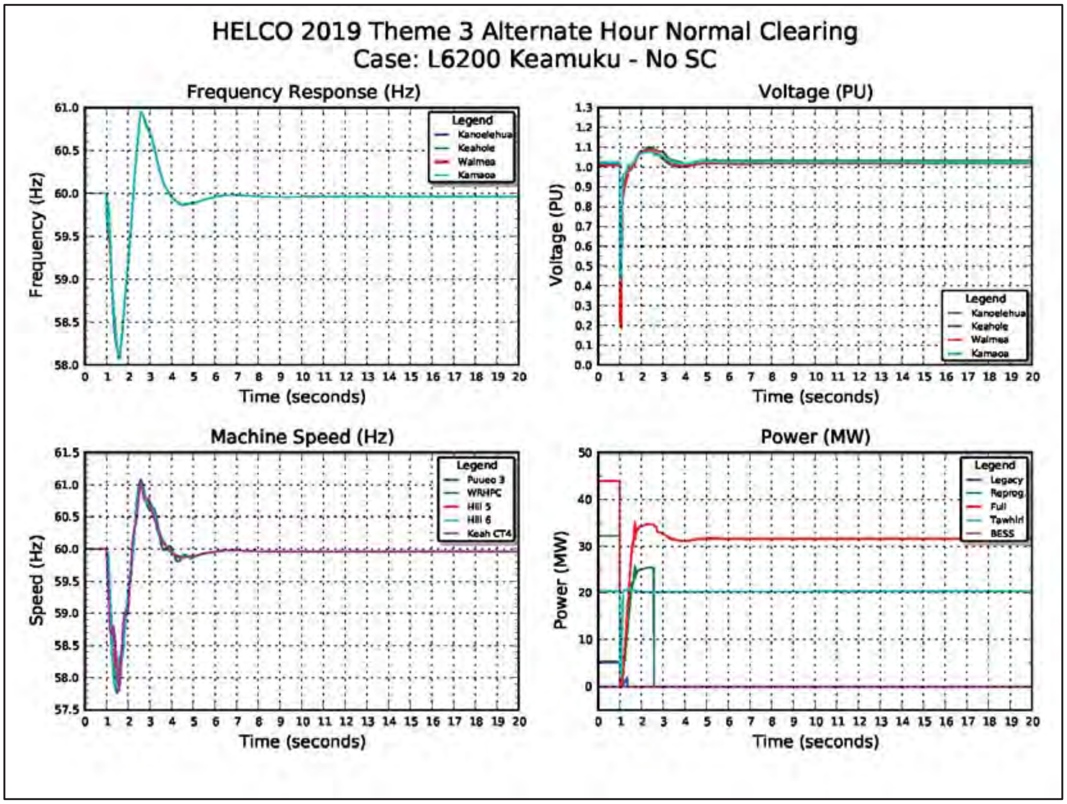

Figure O-349. System Performance Normally Cleared Fault

Figure O-349 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 81 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 58.1 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001 and/or improve the stability margin of the system. The analysis was performed for the L6200 circuit only.

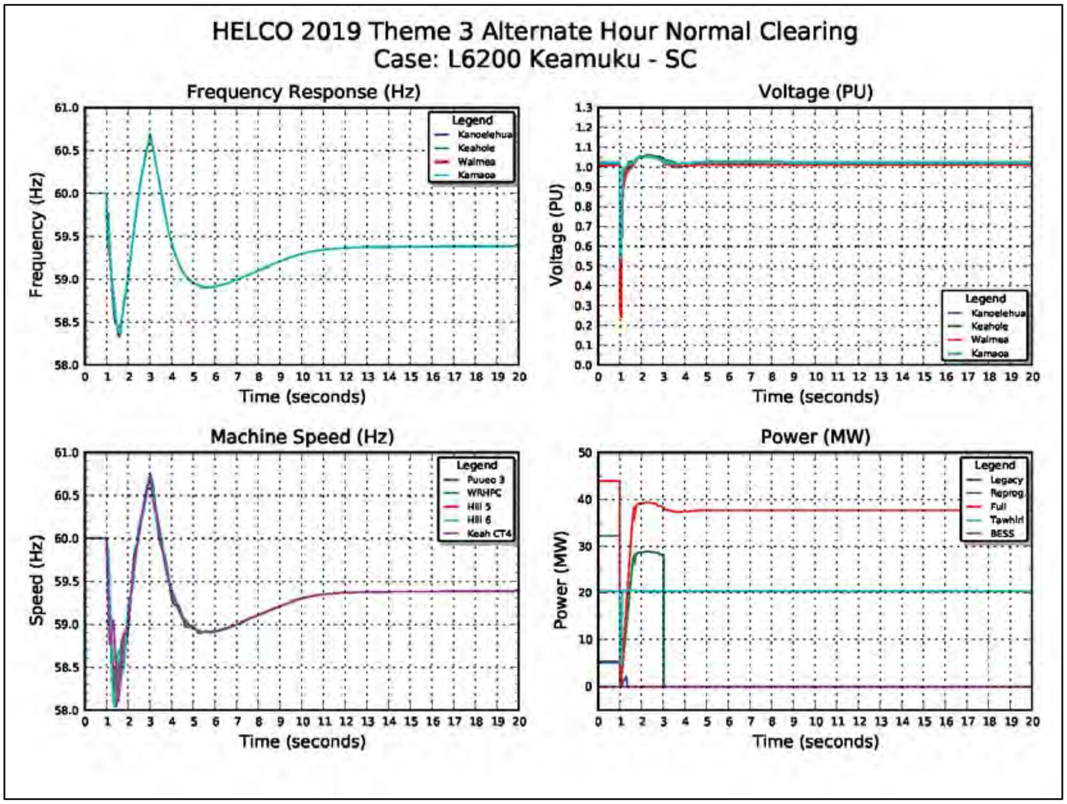

Figure O-350. Normally Cleared Fault Sensitivity Synchronous Condenser

Figure O-350 shows system performance with the addition of two synchronous condensers totaling 34 MVA located at Keahole. The synchronous condensers add inertia, short circuit current, voltage support/ MVAR capability, and increases the magnetic strength of the system. Frequency response improves with the synchronous condenser as the frequency nadir is elevated to 58.4 Hz, reducing UFLS to three blocks but the system is not in compliance with TPL-001.

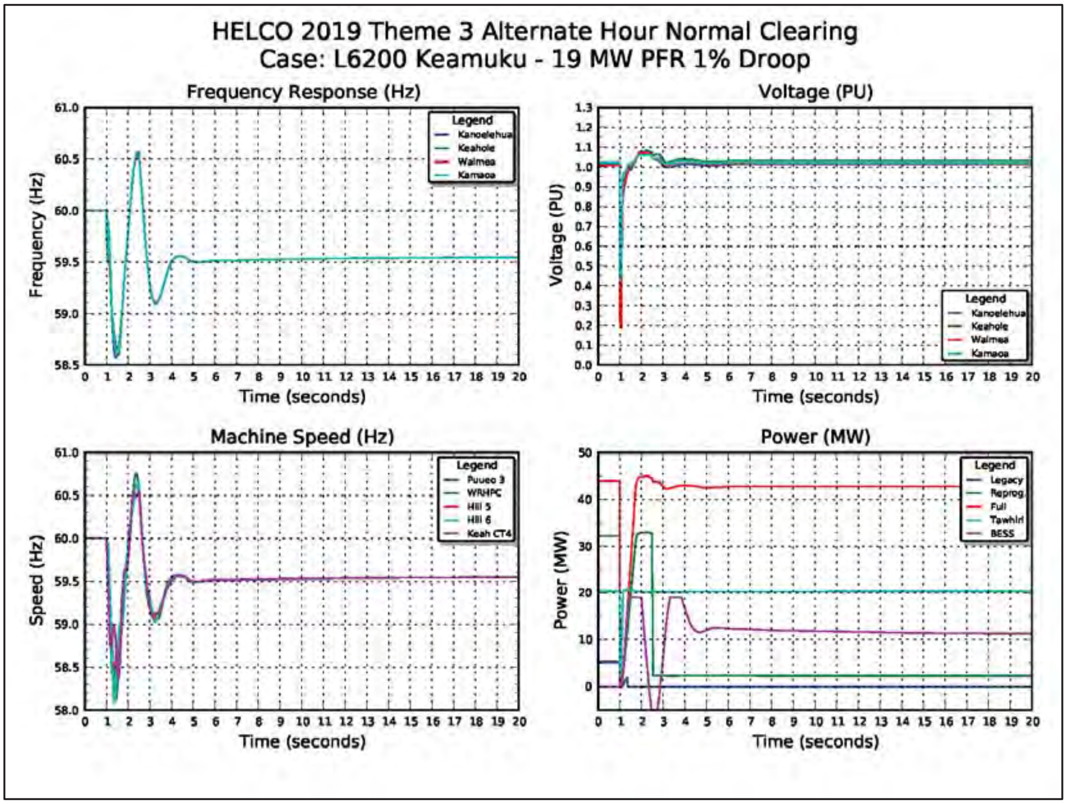

Figure O-351. Normally Cleared Fault Sensitivity 19 MW PFR

Figure O-351 shows system performance with the addition of 19 MW PFR at 1% droop response. For the purpose of this analysis, a 19 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 19 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawaiʻi, the critical busses with the highest MVAR demand are the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Sat 2/29/20 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146	19.6	5.4	12.6
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	49.7	10.3	31.2
Hill 5	13.5	5.0	2.20	15.6	34	12.1	1.4	7.1
Hill 6	20.5	8.0	2.53	27.5	70	18.0	2.5	10.0
Puna	15.5	6.0	4.63	18.8	87	6.2	9.3	0.2
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	19.0	1.0	12.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31			
Synch. Cond. 2	0.0	0.0	2.00	18.8	38			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.6		
Apollo	20.5	0.0						
HRD	10.5	0.0				0.7		
Hydro	16.8	0				9		
Wind	31.0	0				1		
DG-PV	128.8	0						
Total Kinetic Energy						861		
Total Load						171		
Total Thermal Generation						161		
Total Renewable Generation						10		
Total Storage						0		
Total Generation						171		
Excess Generation						0		
Total Up Regulation						31		
Total Down Regulation						88		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-155. Unit Commitment and Dispatch 2020 QV Analysis

Table O-155shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Sat 2/29/20 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	1.2	29.2	-20.8
Keahole STCC	31.6	-23.1	31.6	0.0	-54.7
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	-0.1	52.0	-30.4
Hill 5	6.1	-5.5	2.2	3.9	-7.7
Hill 6	13.3	-11.4	3.8	9.5	-15.2
Puna	14.3	-8.9	-0.7	15.1	-8.2
Keah CT2	15.0	-11.5			
Puna CT3	15.6	-11.0	-1.2	16.8	-9.8
Synch. Cond. 1	11.6	-9.4			
Synch. Cond. 2	14.3	-8.9			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	0.4	3.6	-4.4
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			36.8		
Total Renewable MVAR Generation			0.4		
Total Cap Bank MVAR			24.6		
Charging MVAR			16.0		
Total MVAR Supply			77.9		
Total MVAR Load			43.1		
Total MVAR Losses			34.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				130	
Total MVAR Absorb Capability					-151.3

Table O-156. MVAR Capability 2020 QV Analysis

Table O-156 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
48	L8600 Kealia-Kahaluu
49	L8600 Kealia

Table O-157. N-1 Contingencies2020 QV Analysis

Table O-157 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

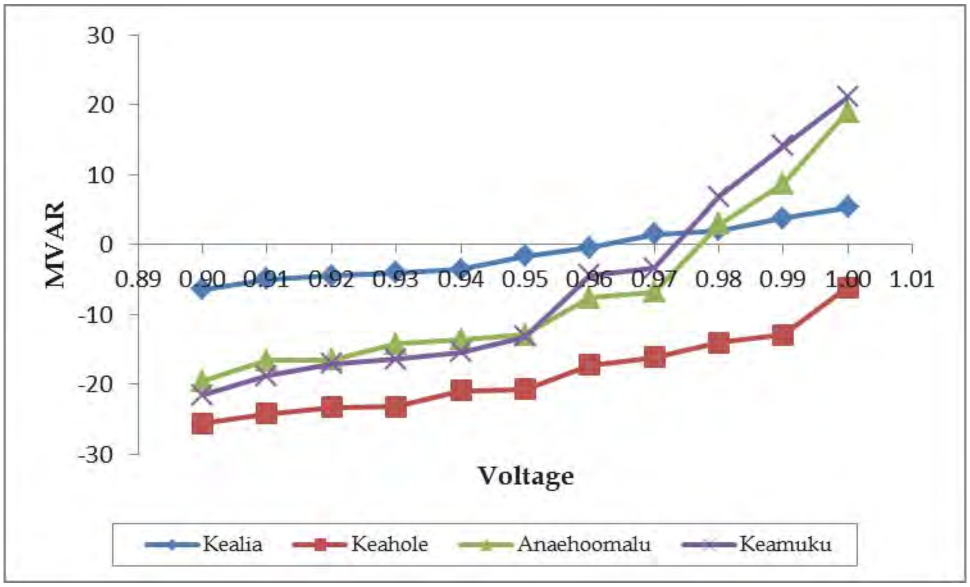

Figure O-352. QV Curves 2020

Figure O-352 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The unit commitment and dispatch meets the reactive power requirements of the system under N-1 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	5	36	4	49	2	49	1	49	0	48	-2	49	-4	48	-4	49	-5	48	-5	48	-6
8400	Keahole	36	-6	36	-13	36	-14	36	-16	36	-17	36	-21	36	-21	36	-23	36	-23	36	-24	36	-26
8500	Anaehoomalu	36	19	36	9	36	3	36	-7	36	-8	36	-13	36	-14	36	-14	36	-17	36	-17	36	-20
8700	Keamuku	37	21	37	14	36	7	36	-3	36	-4	37	-13	36	-15	36	-16	36	-17	36	-19	36	-22

Table O-158. Results 2020 QV Analysis

Table O-158 shows the summary of results for the 2020 QV analysis. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

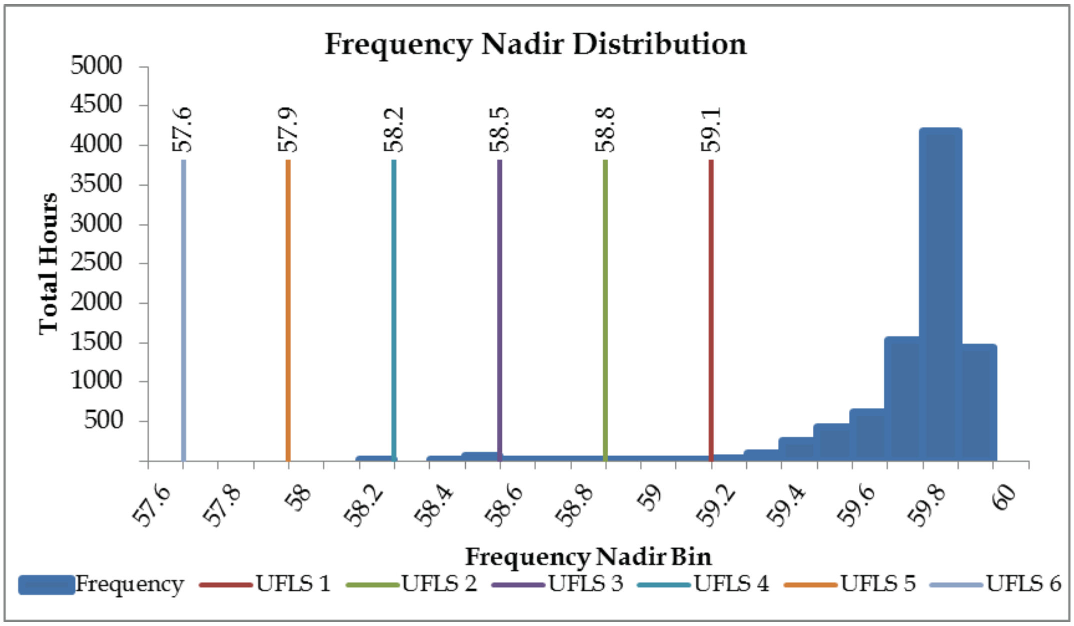

Figure O-353. Frequency Nadir Histogram for 2020

Figure O-353 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. The typical hour was selected from the hourly distribution of 72 hours was 3:00 PM on Friday, May 1. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a distribution of one hour was 12:00 PM on Sunday, July 19. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

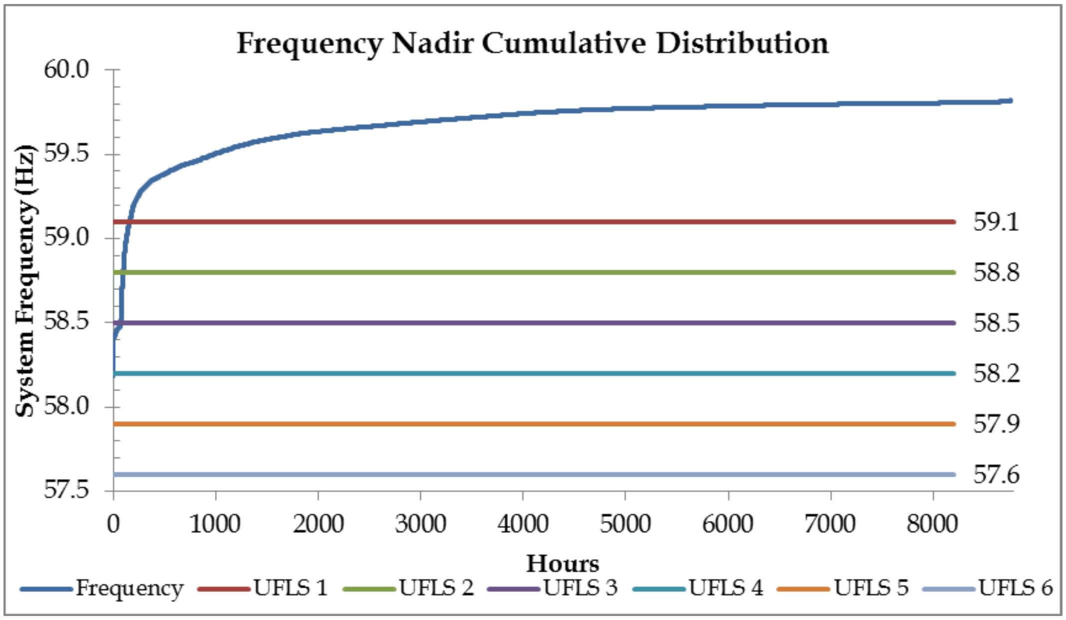

Figure O-354. Frequency Nadir Duration Curve 2020

Figure O-354 shows the frequency nadir duration curve for the Theme 3 resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 74 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Typical Wed 2/26/20 Hour 15			Theme 3 - HEP STCC Trip Boundary Wed 1/29/20 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146						
Keahole DTCC	54.0	7.0	2.77	71.8	199						
Keahole CT4	20.0	7.0	2.10	25.2	53						
Keahole CT5	20.0	7.0	2.10	25.2	53						
HEP STCC	28.5	9.0	1.96	58.9	116	22.0	6.5	13.0	24.0	4.5	15.0
HEP DTCC	60.0	18.5	1.78	94.4	168						
Hill 5	13.5	5.0	2.20	15.6	34						
Hill 6	20.5	8.0	2.53	27.5	70						
Puna	15.5	6.0	4.63	18.8	87						
Keah CT2	13.8	5.0	4.44	22.2	99						
Puna CT3	20.0	7.0	4.96	29.6	147						
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.		0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.		0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9			2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.0			1.6		
Apollo	20.5	0.0				7.9			9.8		
HRD	10.5	0.0									
Wind1	20.0	0.0				6.0			6.0		
Hydro	16.8	0				14			4		
Wind	31.0	0				14			16		
DG-PV	128.8	0				75					
Total Kinetic Energy							394			394	
Total Load							161			82	
Total Thermal Generation							58			62	
Total Renewable Generation							102			20	
Total Storage							0			0	
Total Generation							161			82	
Excess Generation							0			0	
Total Up Regulation							8			4	
Total Down Regulation							27			31	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.6	59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		32.8	60.5Hz Output		0.0

Table O-159. Unit Commitment and Dispatch 2020

Table O-159 shows the unit commitment and dispatch for the typical hour (2/26/20, 3:00 PM) and boundary hour (1/29/20, 3:00 AM).

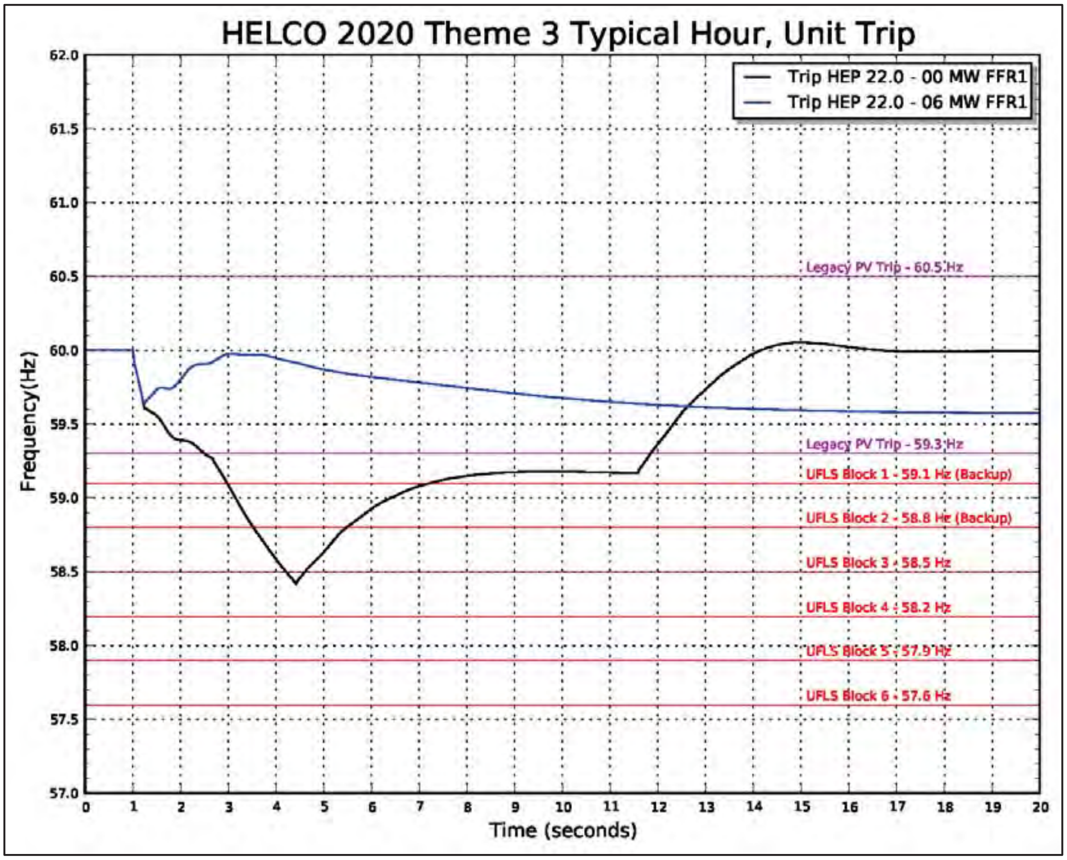

Figure O-355. Frequency Response Profile for FFR1 Typical Hour

Figure O-355 shows the frequency response profile for a HEP trip at 22 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

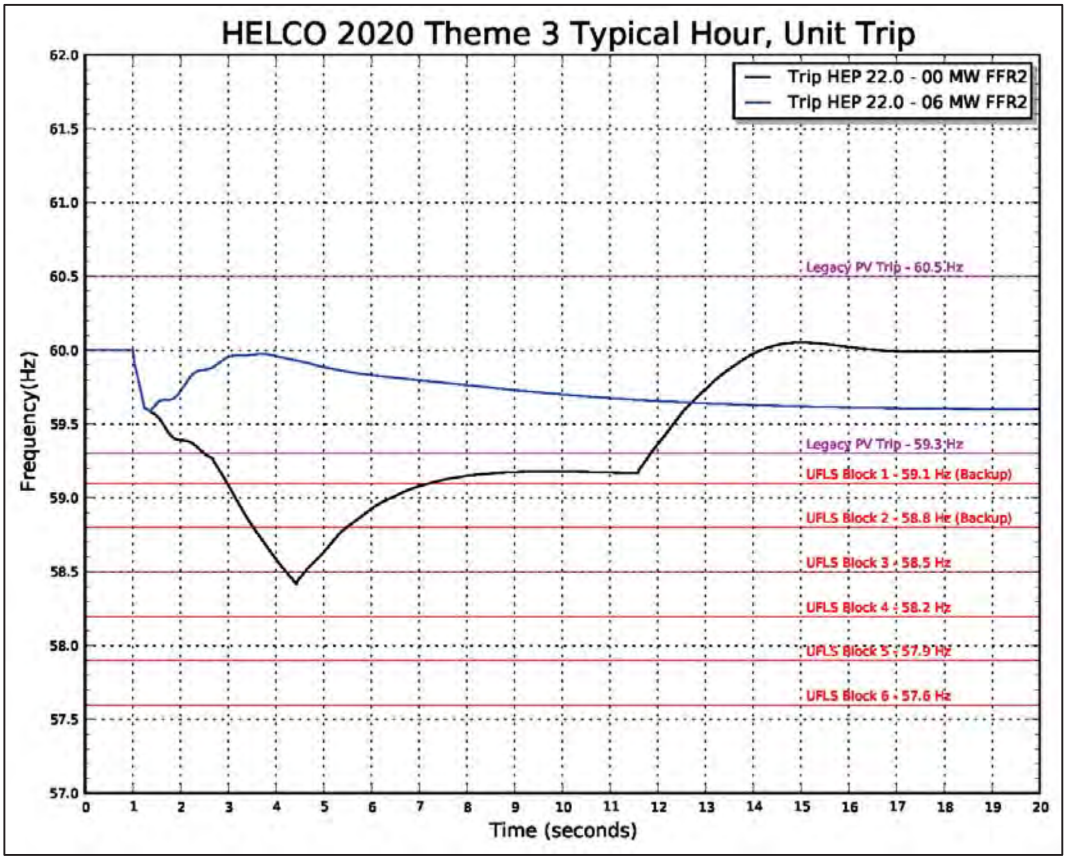

Figure O-356. Frequency Response Profile for FFR2 Typical Hour

Figure O-356 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 6 MW.

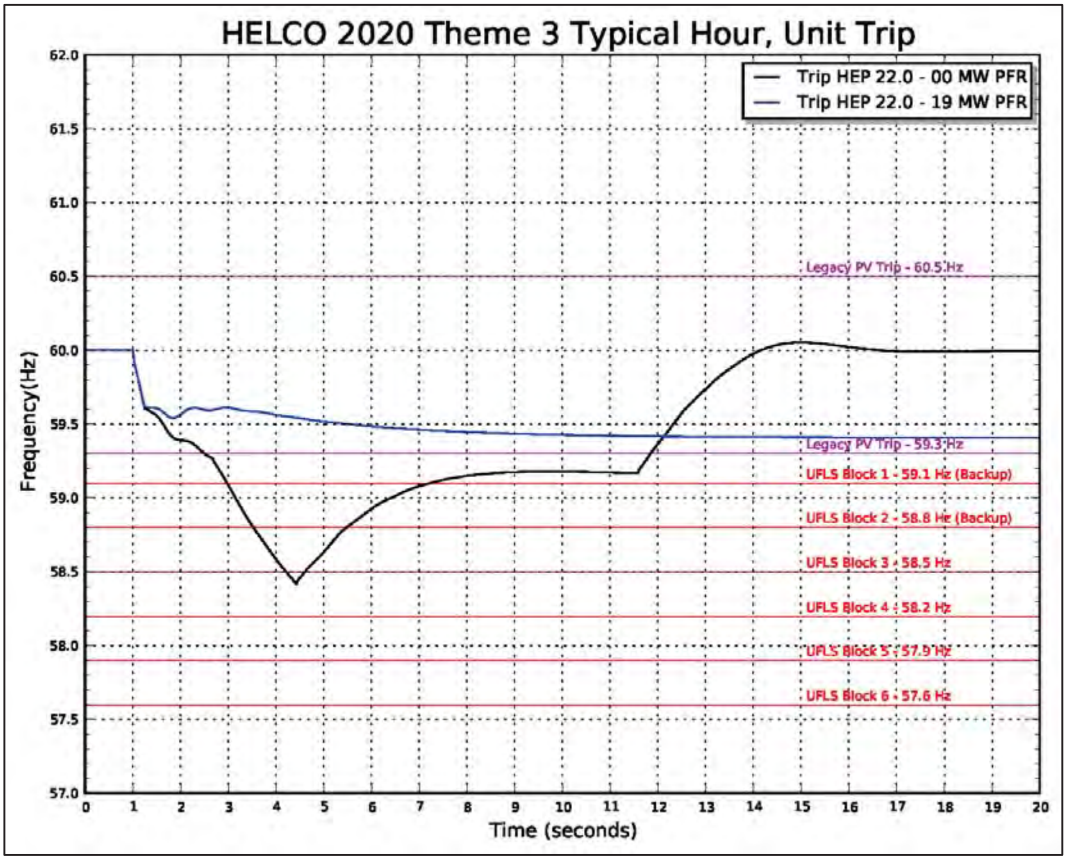

Figure O-357. Frequency Response Profile for PFR Typical Hour

Figure O-357 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 19 MW. This is in addition to the 8 MW of upward regulation from thermal generation.

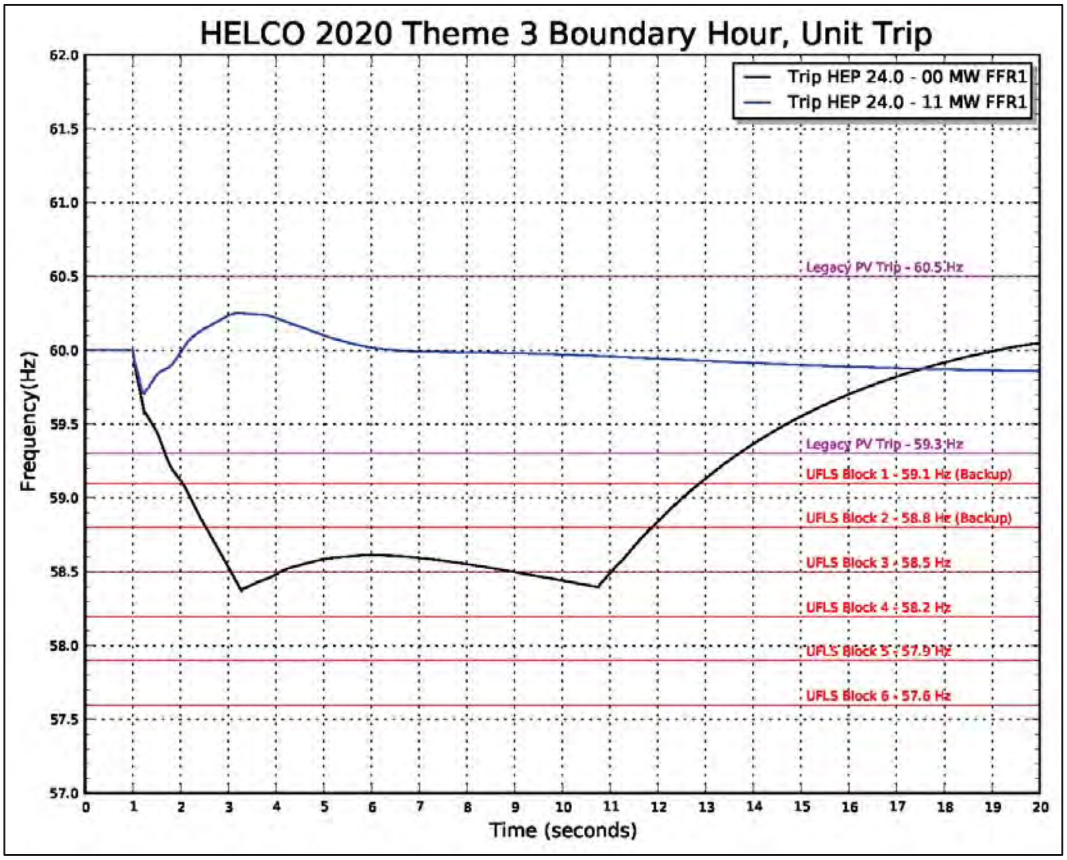

Figure O-358. Frequency Response Profile for FFR1 Boundary Hour

Figure O-358 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 326 MW-sec. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11 MW.

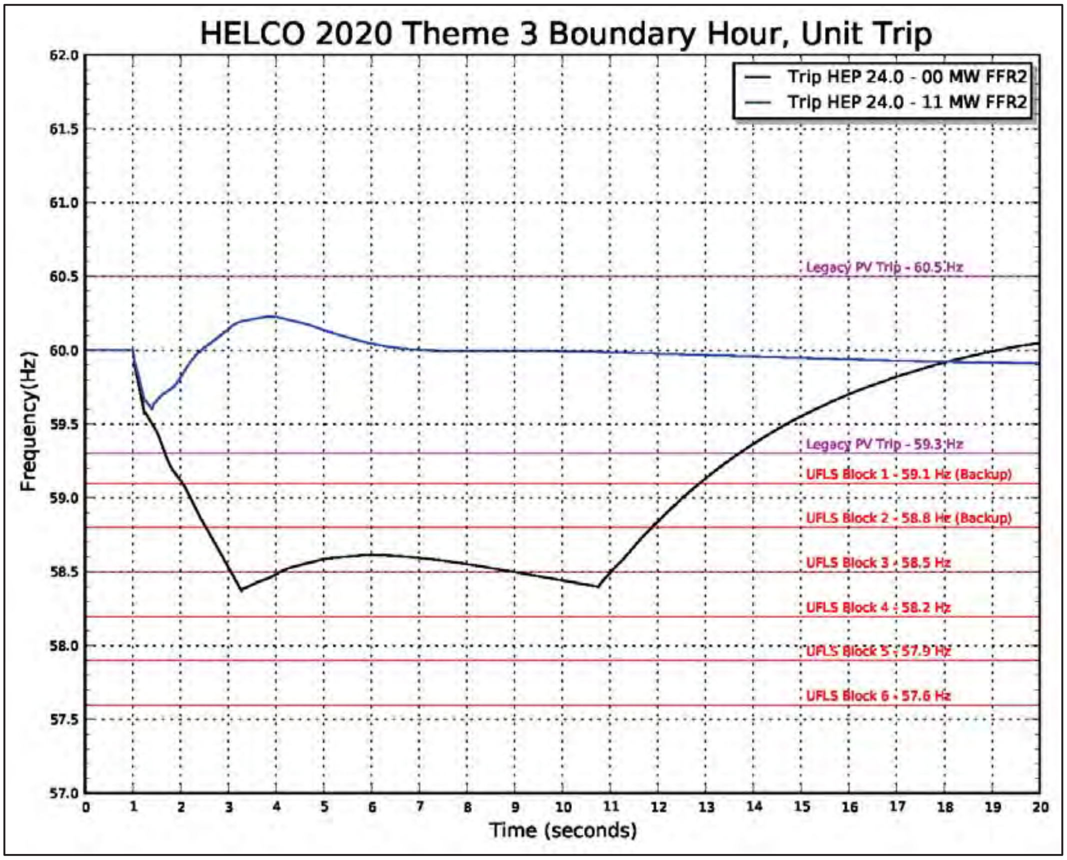

Figure O-359. Frequency Response Profile for FFR2 Typical Hour

Figure O-359 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

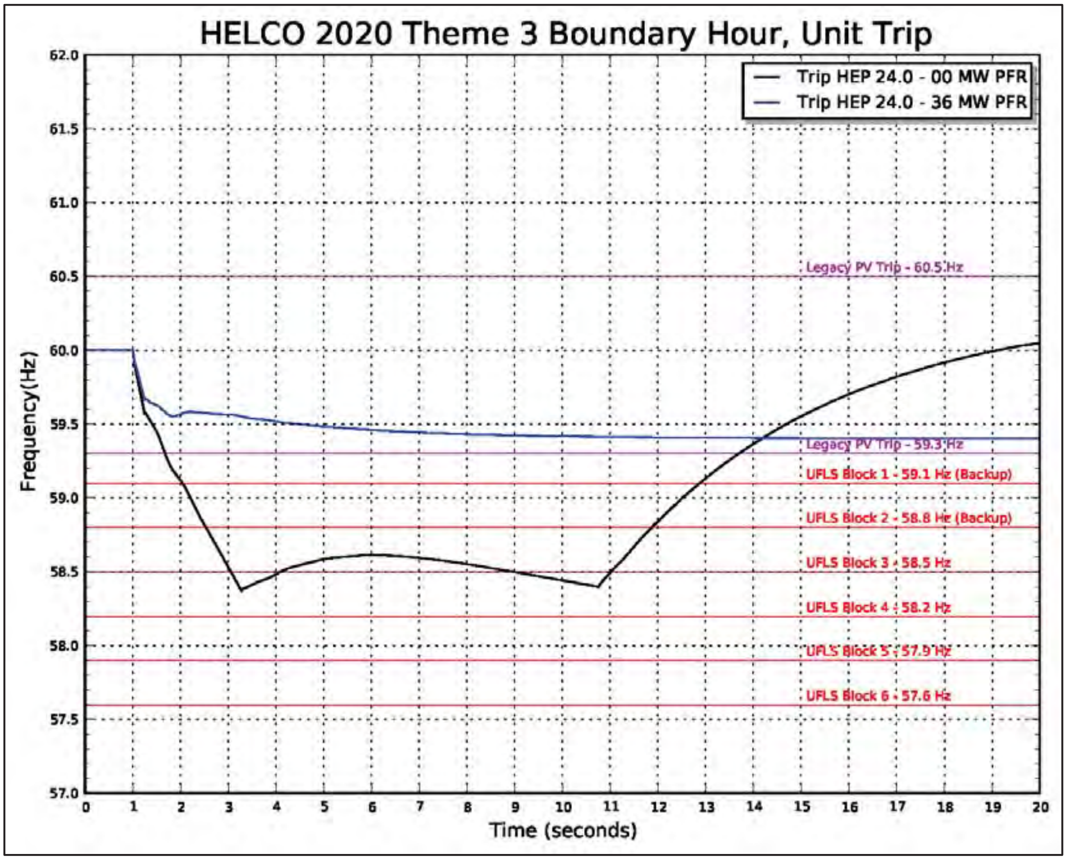

Figure O-360. Frequency Response Profile for PFR Typical Hour

Figure O-360 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 36 MW. This is in addition to the 4 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most sever disturbance on the transmission system typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					Theme 3 - Fault Sat 2/8/20 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.2	4.8	11.2
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	11.2	17.3	2.2
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				18.3		
HRD	10.5	0.0				2.5		
Wind1	20.0	0.0				3.0		
Hydro	16.8	0				2		
Wind	31.0	0				24		
DG-PV	128.8	0				86		
Total Kinetic Energy						365		
Total Load						156		
Total Thermal Generation						44		
Total Renewable Generation						112		
Total Storage						0		
Total Generation						156		
Excess Generation						0		
Total Up Regulation						22		
Total Down Regulation						13		
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.9 56.6		59.3Hz Output 60.5Hz Output		5.3 37.9

Table O-160. Unit Commitment and Dispatch Fault Analysis

Table O-160 shows the unit commitment and dispatch for the 69 kV fault analysis. The capacity of DG-PV is 86 MW.

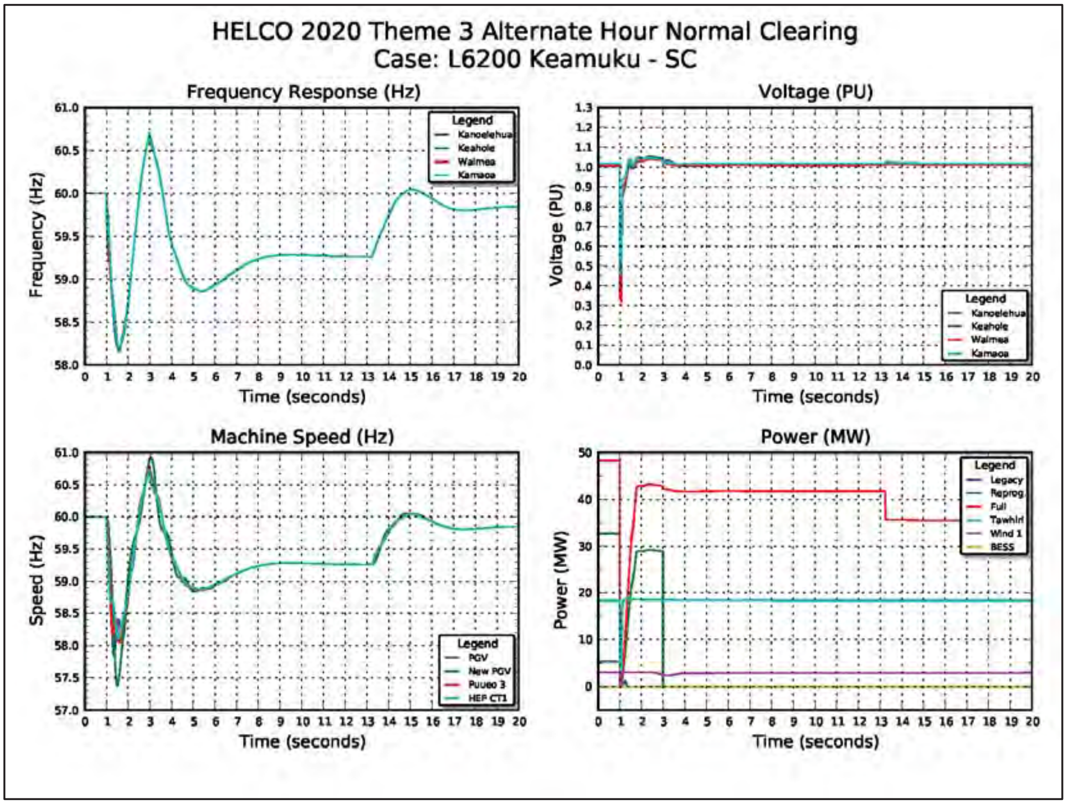

Figure O-361. System Performance Normally Cleared Fault

Figure O-361 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU low voltage ride-through threshold for inverter-based PV generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 86 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and four blocks of UFLS is able to stabilize system frequency at 58.2 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

The system remains stable for normally cleared faults on any Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet the requirements of TPL-001. Analysis was performed on the L6200 circuit only.

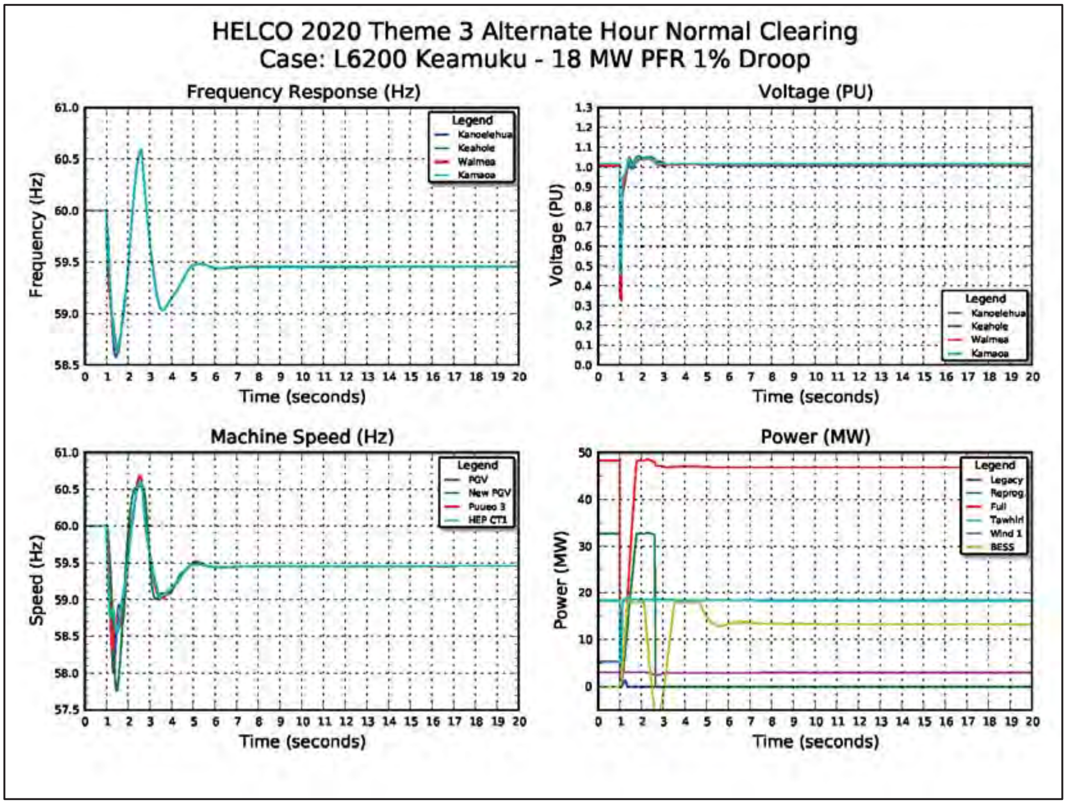

Figure O-362. Normally Cleared Fault Sensitivity 18 MW PFR

Figure O-362 shows system performance with the addition of 18 MW PFR at 1% droop response. For the purpose of this analysis, an 18 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, the Tawhiri wind plant, and the 18 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawaiʻi, the critical busses with the highest MVAR demand are the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 -QV Dispatch Sat 2/27/21 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146	22.0	3.0	15.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	48.6	11.4	30.1
Hill 5	13.5	5.0	2.20	15.6	34	13.5	0.0	8.5
Hill 6	20.5	8.0	2.53	27.5	70	20.0	0.5	12.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	17.1	2.9	10.1
Synch. Cond. 1	0.0	0.0	2.00	15.6	31			
Synch. Cond. 2	0.0	0.0	2.00	18.8	38			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.7		
Apollo	20.5	0.0						
HRD	10.5	0.0				0.8		
Hydro	16.8	0				10		
Wind	31.0	0				1		
DG-PV	133.8	0						
Total Kinetic Energy							774	
Total Load							168	
Total Thermal Generation							158	
Total Renewable Generation							10	
Total Storage							0	
Total Generation							168	
Excess Generation							0	
Total Up Regulation							19	
Total Down Regulation							90	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.1
	60.5Hz Capacity			56.6		60.5Hz Output		0.6

Table O-161. Unit Commitment and Dispatch 2021 QV Analysis

Table O-161 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Sat 2/27/21 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	1.0	29.4	-20.5
Keahole STCC	31.6	-23.1	27.5	4.1	-50.6
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	-1.1	53.0	-29.4
Hill 5	6.1	-5.5	1.5	4.6	-7.1
Hill 6	13.3	-11.4	2.7	10.6	-14.1
Puna	6.7	-6.2			
Keah CT2	15.0	-11.5			
Puna CT3	15.6	-11.0	-5.5	21.2	-5.5
Synch. Cond. 1	11.6	-9.4			
Synch. Cond. 2	14.3	-8.9			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	0.1	3.9	-4.1
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			26.1		
Total Renewable MVAR Generation			0.1		
Total Cap Bank MVAR			32.4		
Charging MVAR			16.2		
Total MVAR Supply			74.8		
Total MVAR Load			42.3		
Total MVAR Losses			32.5		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				127	
Total MVAR Absorb Capability					-131.3

Table O-162. MVAR Capability 2021 QV Analysis

Table O-162 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
48	L8600 Kealia-Kahaluu
49	L8600 Kealia

Table O-163. N-1 Contingencies2021 QV Analysis

Table O-163 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

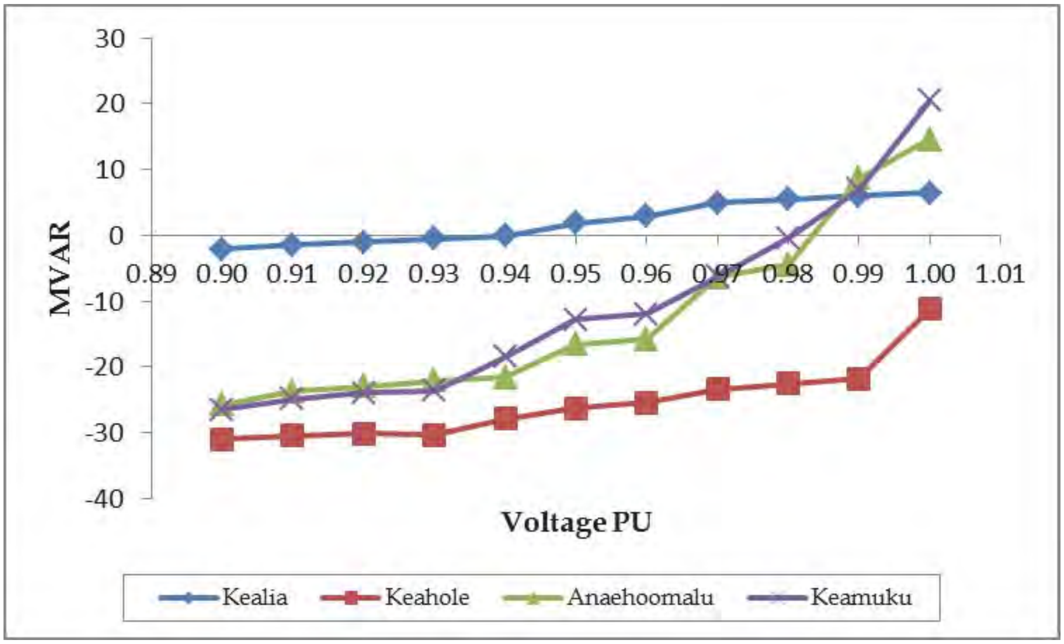

Figure O-363. QV Curves 2021

Figure O-363 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The Kealia bus requires 2 MVAR to maintain bus voltage at 0.95 PU. For the purpose of this analysis, the unit commitment and dispatch meets the reactive power requirements of the system.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	6	50	6	50	5	50	5	50	3	50	2	50	0	50	-1	50	-1	50	-2	50	-2
8400	Keahole	36	-11	36	-22	36	-23	36	-23	36	-25	36	-26	36	-28	36	-30	36	-30	36	-31	36	-31
8500	Anaehoomalu	36	15	36	9	45	-5	36	-6	55	-16	36	-17	36	-22	36	-22	36	-23	36	-24	36	-26
8700	Keamuku	36	20	36	7	36	0	36	-6	36	-12	36	-13	36	-19	36	-24	36	-24	36	-25	36	-27

Table O-164. Results 2021 QV Analysis

Table O-164 shows the summary of results for the 2021 QV analysis. The Kealia bus requires 5 MVAR to maintain bus voltage at 0.95 PU for an outage of L8600.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

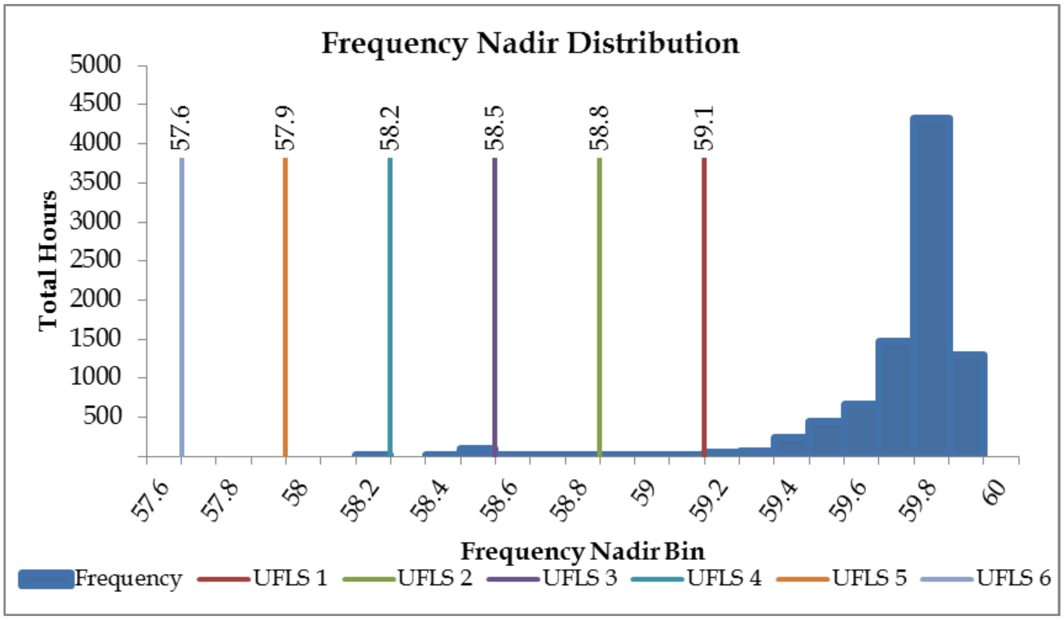

Figure O-364. Frequency Nadir Histogram for 2021

Figure O-364 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A typical hour was selected from the maximum distribution of 95 hours was 1:00 PM on Wednesday, June 23. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a distribution of one hour was 11:00 AM on Sunday, March 3. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

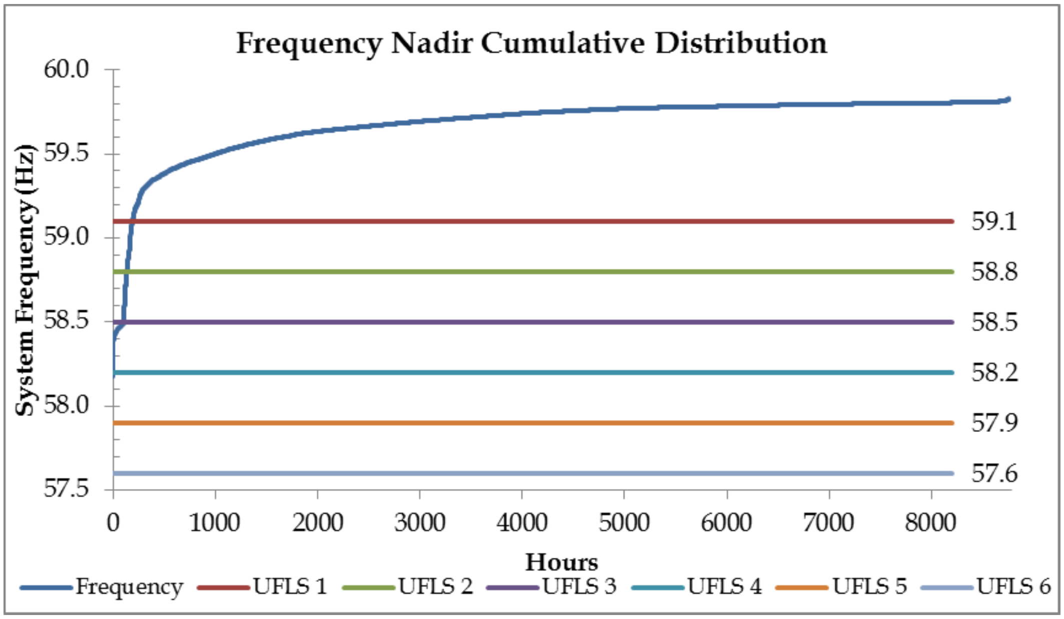

Figure O-365. Frequency Nadir Duration Curve 2021

Figure O-365 shows the frequency nadir duration curve for the Theme 3 resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 103 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Typical Wed 6/23/21 Hour 13			Theme 3 - HEP STCC Trip Boundary Wed 3/3/21 Hour 11		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146						
Keahole DTCC	54.0	7.0	2.77	71.8	199						
Keahole CT4	20.0	7.0	2.10	25.2	53						
Keahole CT5	20.0	7.0	2.10	25.2	53						
HEP STCC	28.5	9.0	1.96	58.9	116	25.9	2.6	16.9	24.7	3.8	15.7
HEP DTCC	60.0	18.5	1.78	94.4	168						
Hill 5	13.5	5.0	2.20	15.6	34						
Hill 6	20.5	8.0	2.53	27.5	70						
Puna	15.5	6.0	4.63	18.8	87						
Keah CT2	13.8	5.0	4.44	22.2	99						
Puna CT3	20.0	7.0	4.96	29.6	147						
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.		0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.		0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.6			3.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.7			3.6		
Apollo	20.5	0.0				14.6			7.5		
HRD	10.5	0.0				8.8			0.5		
Wind1	20.0	0.0				10.0			2.0		
Hydro	16.8	0				5			7		
Wind	31.0	0				33			10		
DG-PV	133.8	0				71			83		
Total Kinetic Energy						394			394		
Total Load						172			162		
Total Thermal Generation						62			61		
Total Renewable Generation						110			100		
Total Storage						0			0		
Total Generation						172			162		
Excess Generation						0			0		
Total Up Regulation						4			5		
Total Down Regulation						31			30		
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.9 56.6		59.3Hz Output 60.5Hz Output		4.3 30.6	59.3Hz Output 60.5Hz Output		5.2 36.8

Table O-165. Unit Commitment and Dispatch 2021

Table O-165 shows the unit commitment and dispatch for the typical hour (6/23/21, 1:00 PM) and boundary hour (3/3/21, 11:00 AM).

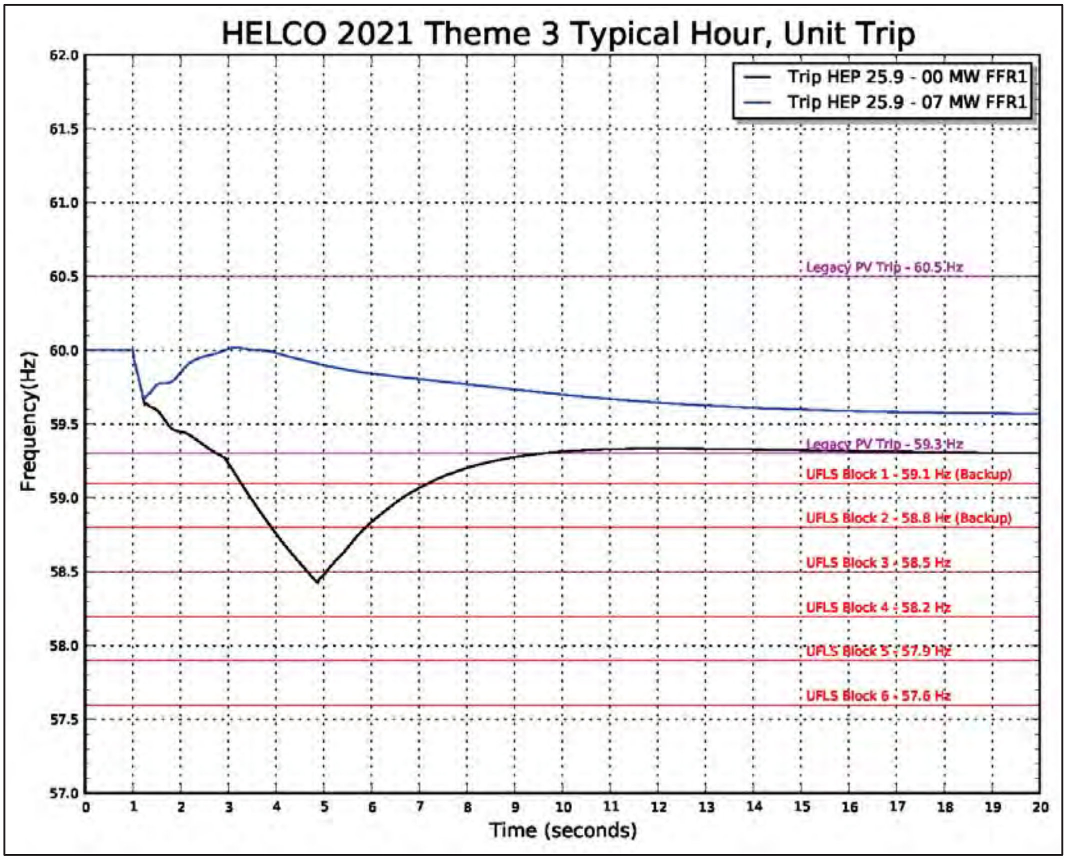

Figure O-366. Frequency Response Profile for FFR1 Typical Hour

Figure O-366 shows the frequency response profile for a HEP trip at 26 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

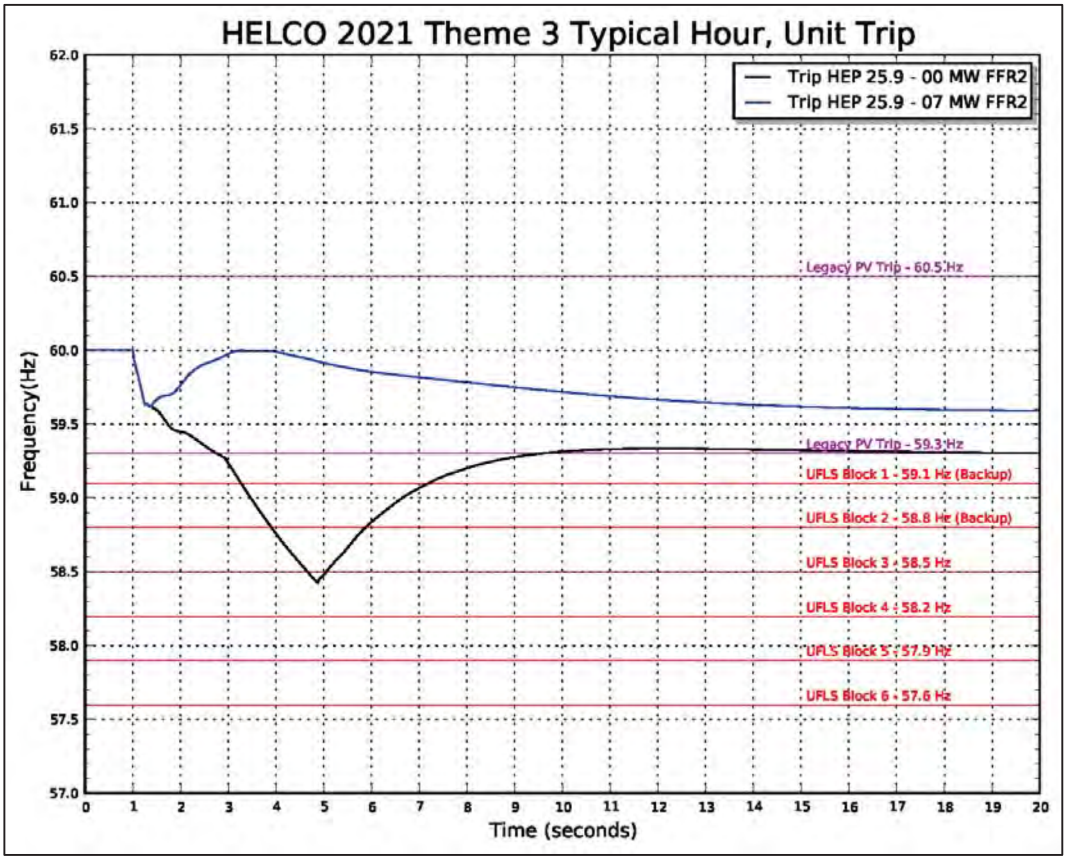

Figure O-367. Frequency Response Profile for FFR2 Typical Hour

Figure O-367 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW.

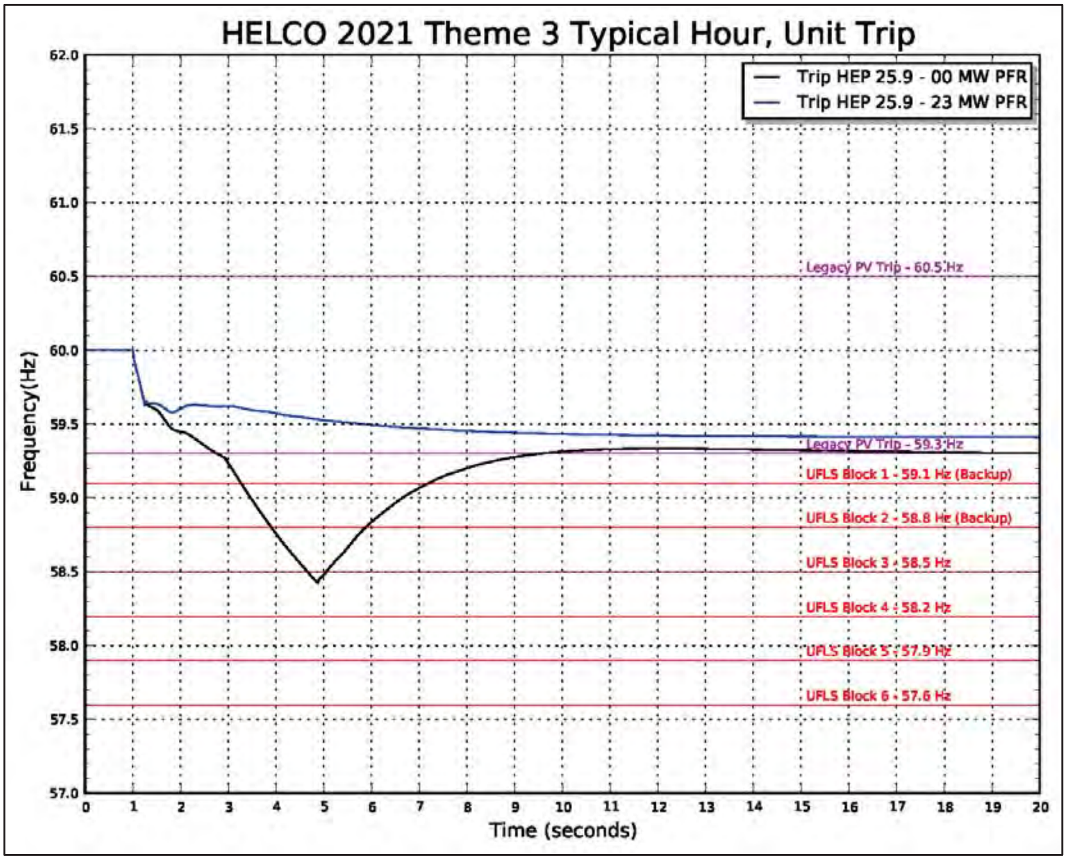

Figure O-368. Frequency Response Profile for PFR Typical Hour

Figure O-368 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 23 MW. This is in addition to the 4 MW of from thermal generation.

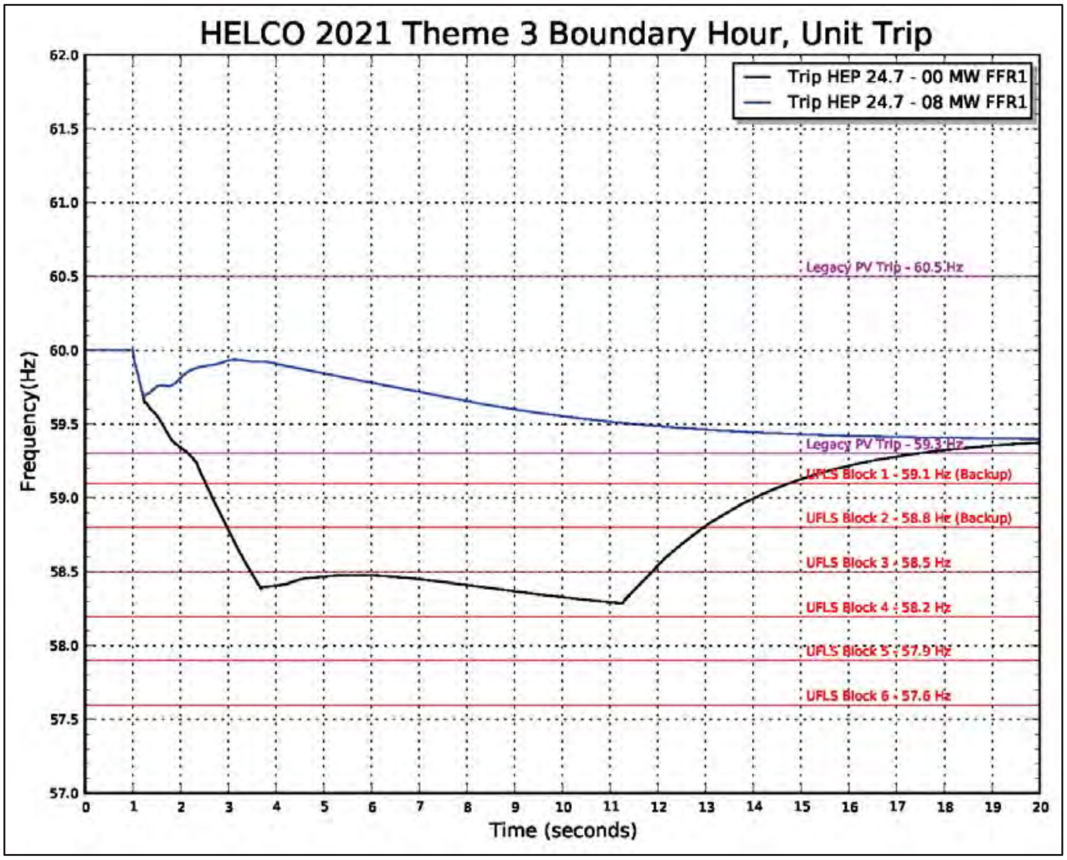

Figure O-369. Frequency Response Profile for FFR1 Boundary Hour

Figure O-369 shows the frequency response profile for a HEP trip at 25 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

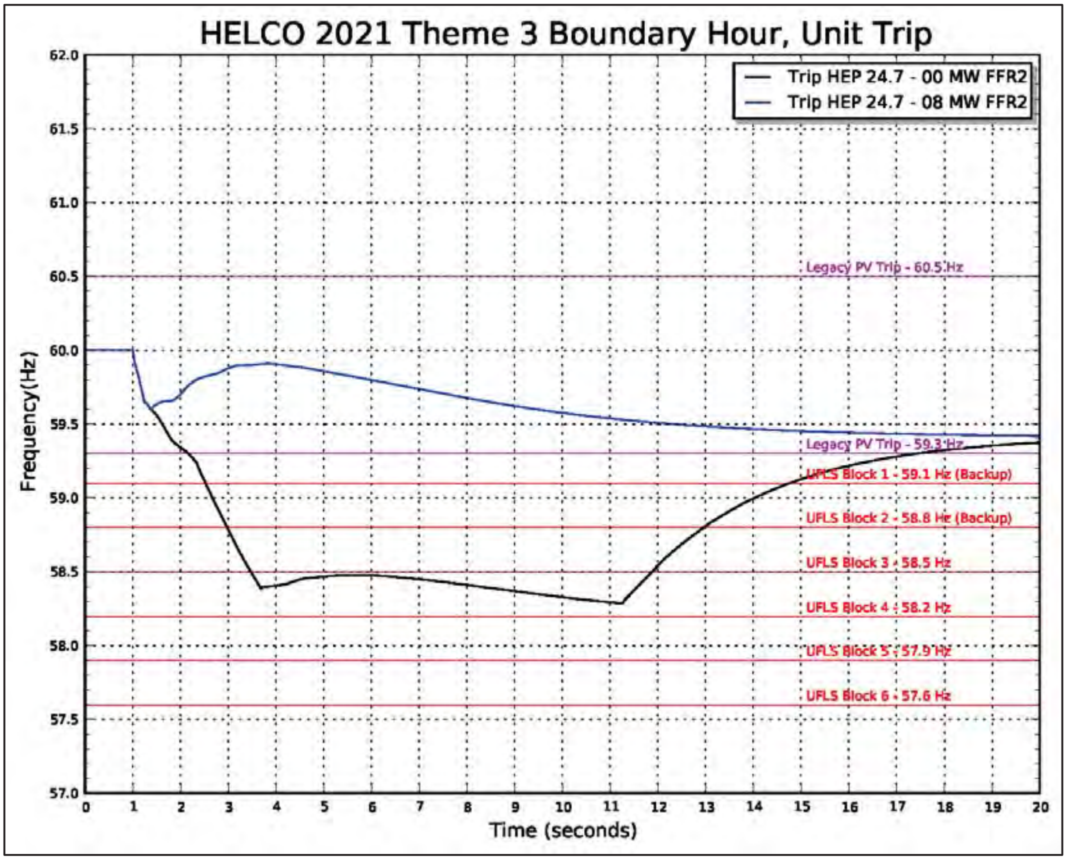

Figure O-370. Frequency Response Profile for FFR2 Boundary Hour

Figure O-370 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 8 MW.

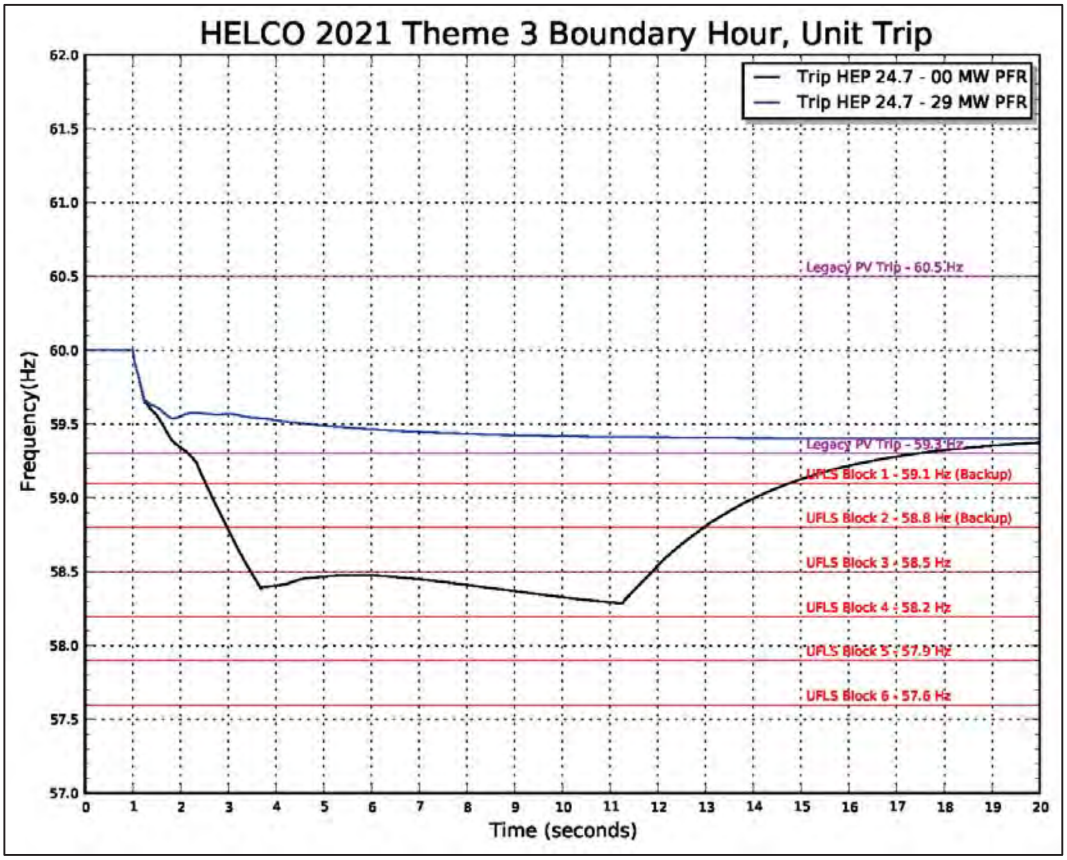

Figure O-371. Frequency Response Profile for FFR1 Boundary Hour

Figure O-371 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 2 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					Theme 3 - Fault Sat 2/6/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.1	4.9	11.1
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	11.2	17.3	2.2
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				18.3		
HRD	10.5	0.0				2.6		
Wind1	20.0	0.0				3.5		
Hydro	16.8	0				2		
Wind	31.0	0				24		
DG-PV	133.8	0				87		
Total Kinetic Energy						365		
Total Load						158		
Total Thermal Generation						44		
Total Renewable Generation						114		
Total Storage						0		
Total Generation						158		
Excess Generation						0		
Total Up Regulation						22		
Total Down Regulation						13		
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.9 56.6		59.3Hz Output 60.5Hz Output		5.4 38.5

Table O-166. Unit Commitment and Dispatch Fault Analysis

Table O-166 shows the unit commitment and dispatch for the 69 kV fault analysis (2/6/20, 1:00 PM).

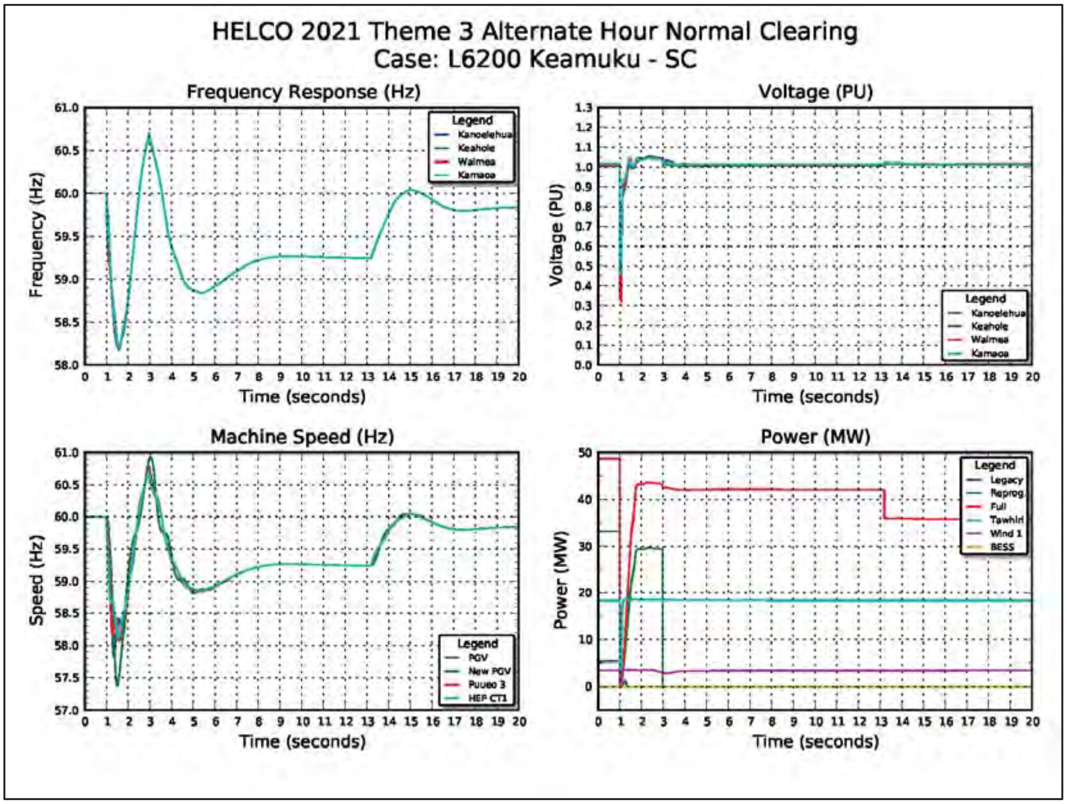

Figure O-372. System Performance Normally Cleared Fault

Figure O-372 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU low voltage ride-through threshold for inverter-based PV generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 87 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and four blocks of UFLS is able to stabilize system frequency at 58.2 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to improve system security. Results will vary for different circuits and dispatch schedules. Further analysis is required to determine an optimal solution to ensure system security.

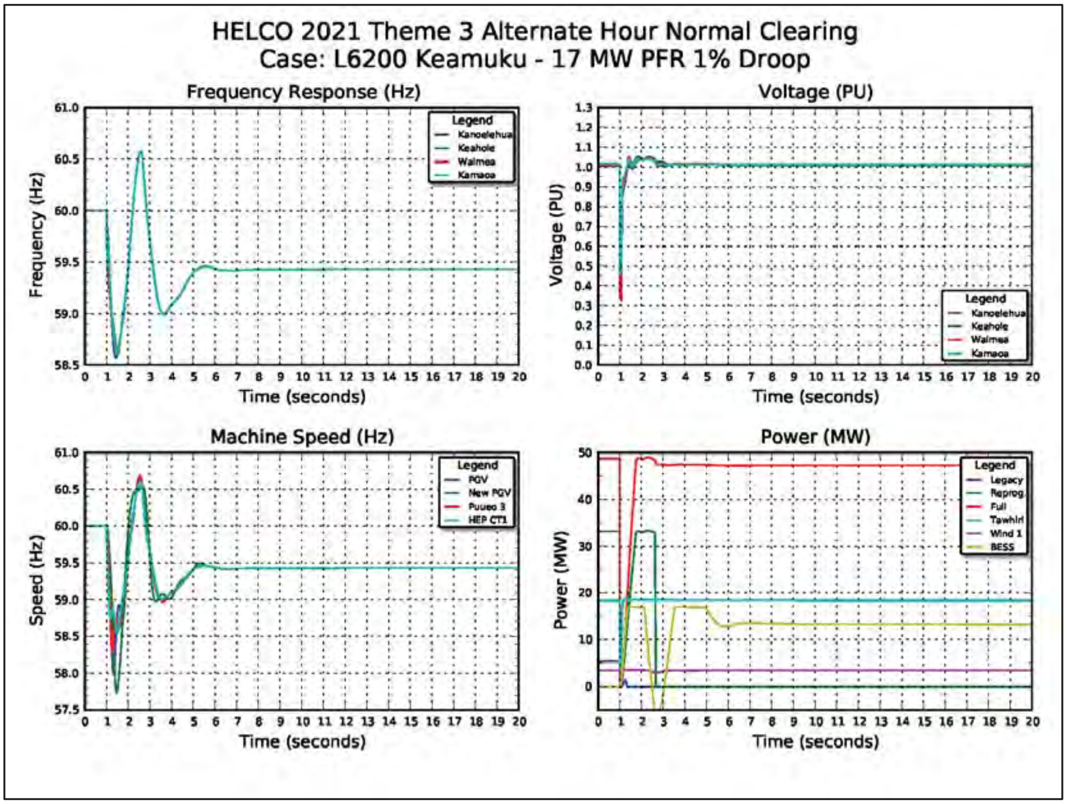

Figure O-373. Normally Cleared Fault Sensitivity 17 MW PFR

Figure O-373 shows system performance with the addition of 17 MW PFR at 1% droop response. For the purpose of this analysis, a 17 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, the Tawhiri wind plant, and the 17 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

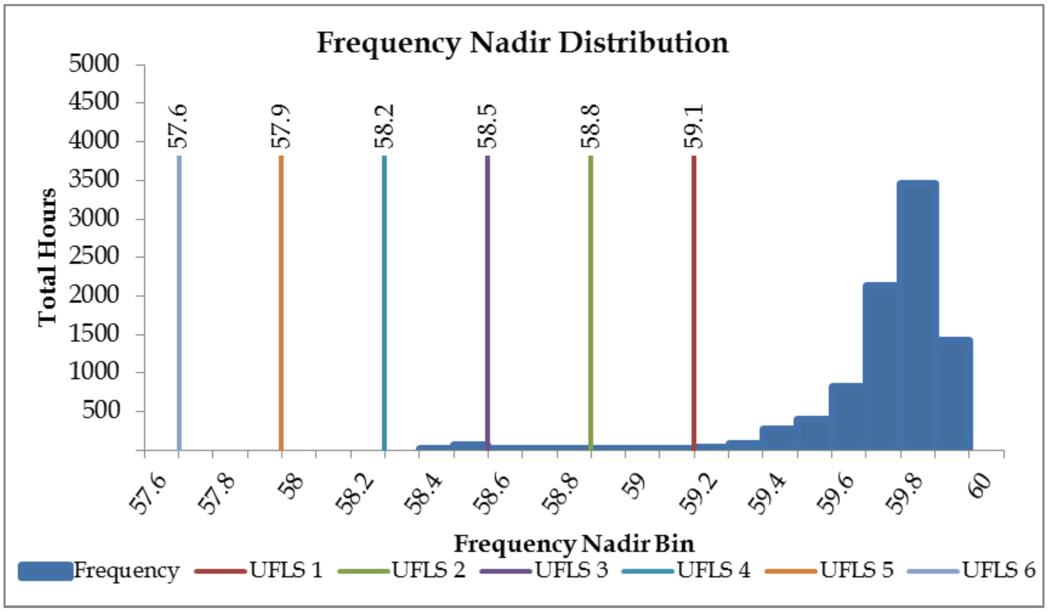

Figure O-374. Frequency Nadir Histogram for 2025

Figure O-374 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 71 hours was 1:00 PM on Sunday, January 19. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

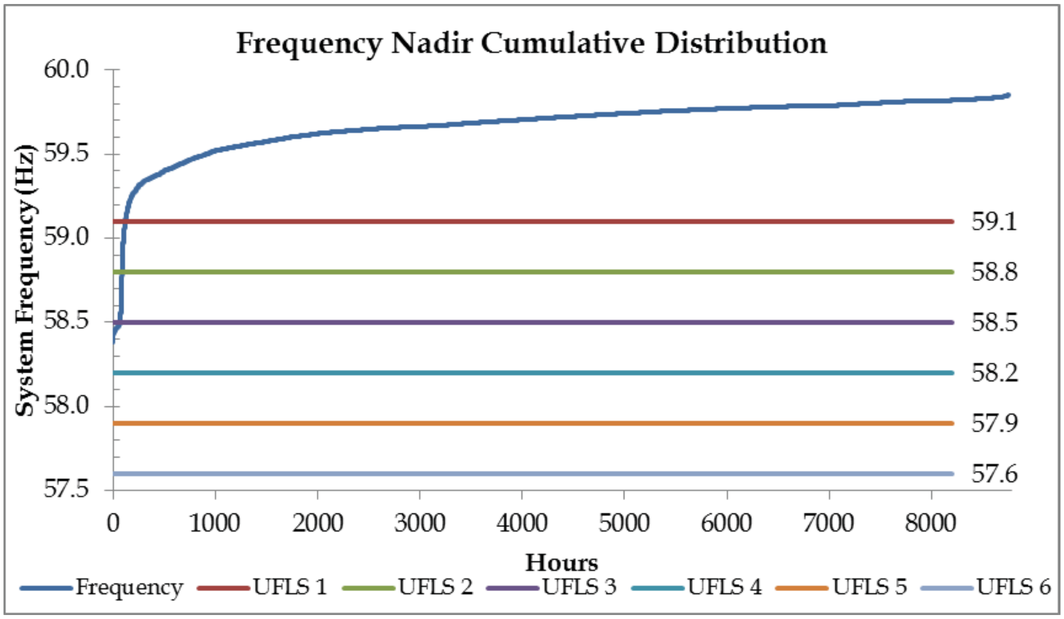

Figure O-375. Frequency Nadir Duration Curve 2025

Figure O-375 shows the frequency nadir duration curve for the Theme 3 resource plan in 2025. The system is at risk of exceeding the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Sun 1/19/25 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.8	4.7	14.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.9		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				4		
Wind	31.0	0				0		
DG-PV	143.0	0				79		
Total Kinetic Energy						594		
Total Load						164		
Total Thermal Generation						80		
Total Renewable Generation						83		
Total Storage						0		
Total Generation						164		
Excess Generation						0		
Total Up Regulation						6		
Total Down Regulation						49		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.4
	60.5Hz Capacity			56.6		60.5Hz Output		31.7

Table O-167. Unit Commitment and Dispatch 2025

Table O-167 shows the unit commitment and dispatch for the boundary hour (1/19/25, 1:00 PM).

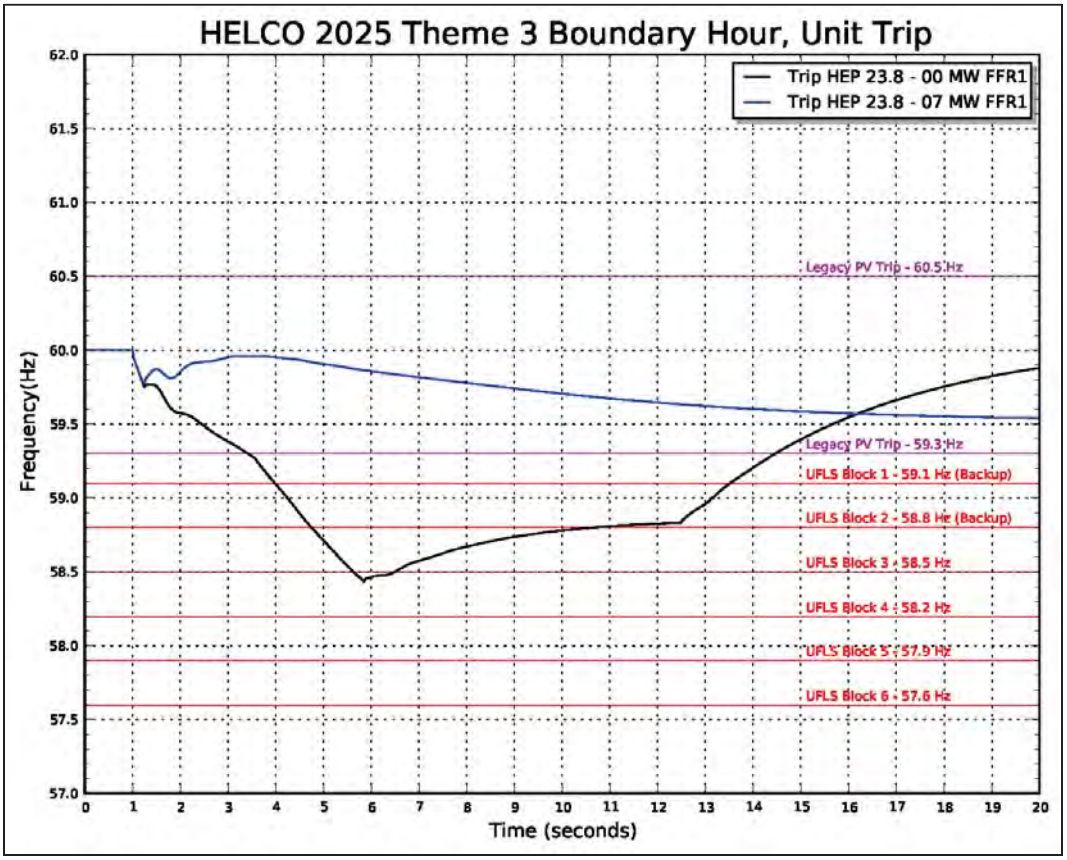

Figure O-376. Frequency Response Profile for FFR1 Boundary Hour

Figure O-376 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 526 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

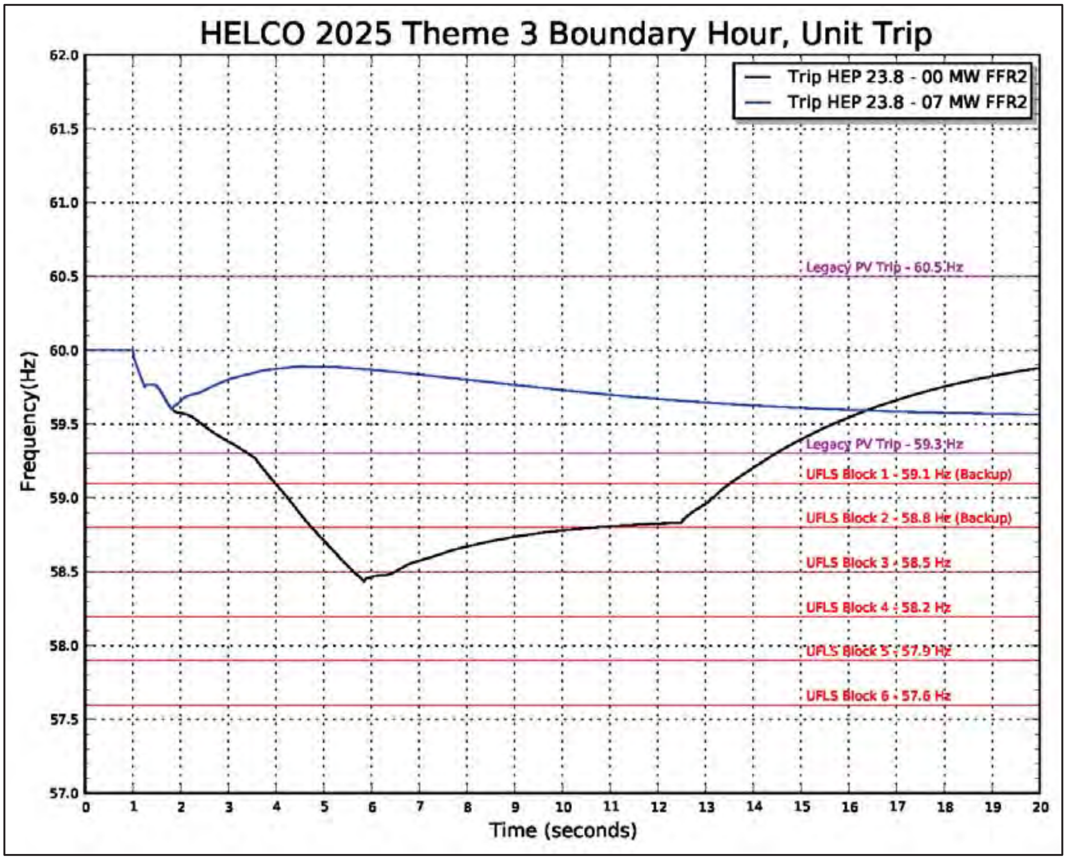

Figure O-377. Frequency Response Profile for FFR2 Boundary Hour

Figure O-377 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW.

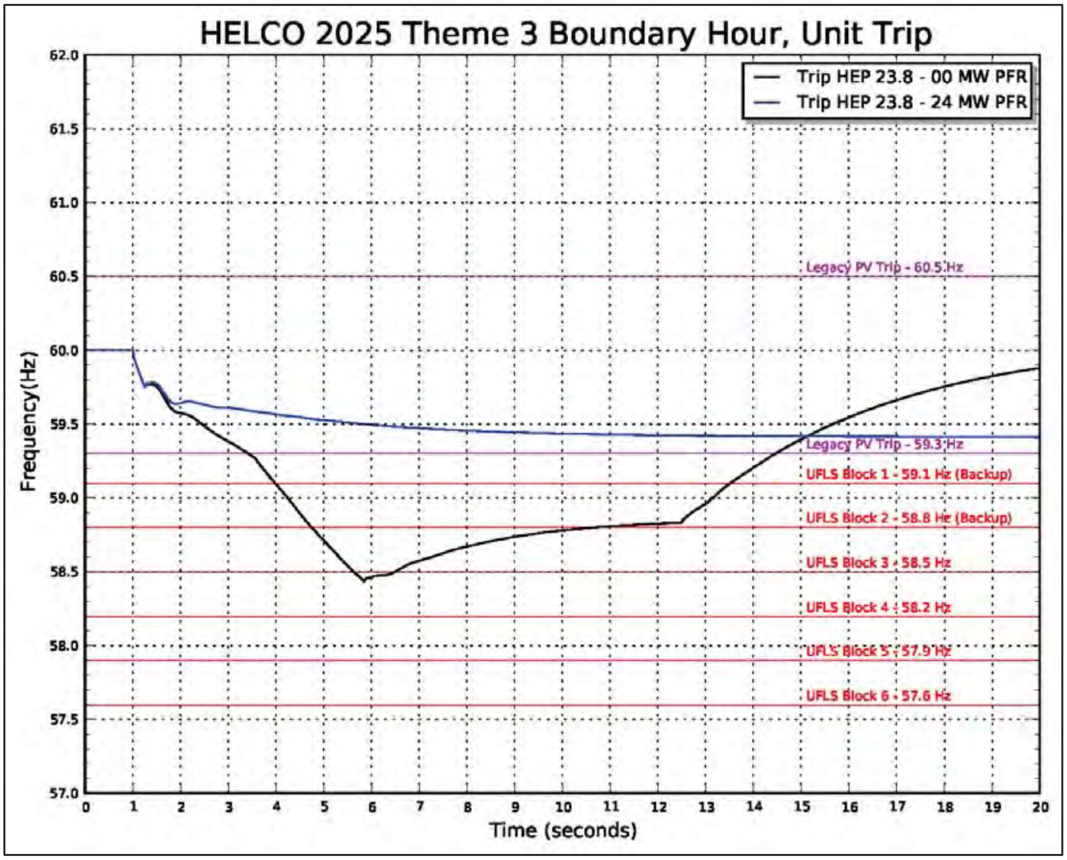

Figure O-378. Frequency Response Profile for PFR Boundary Hour

Figure O-378 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 24MW. This is in addition to the 6 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

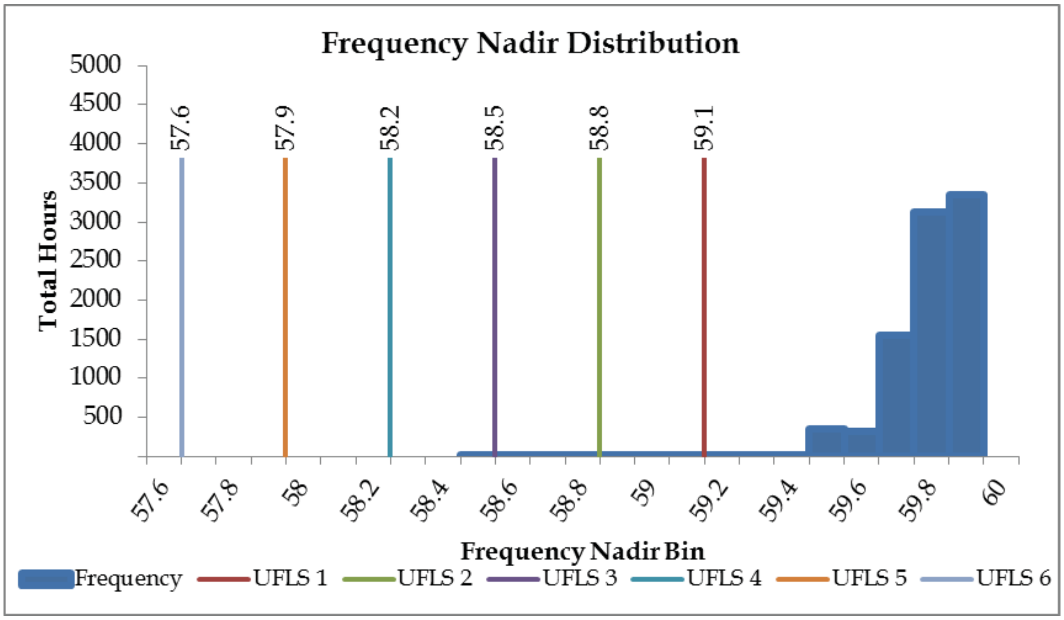

Figure O-379. Frequency Nadir Histogram for 2030

Figure O-379 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 4 hours was 6:00 AM on Tuesday, April 30. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

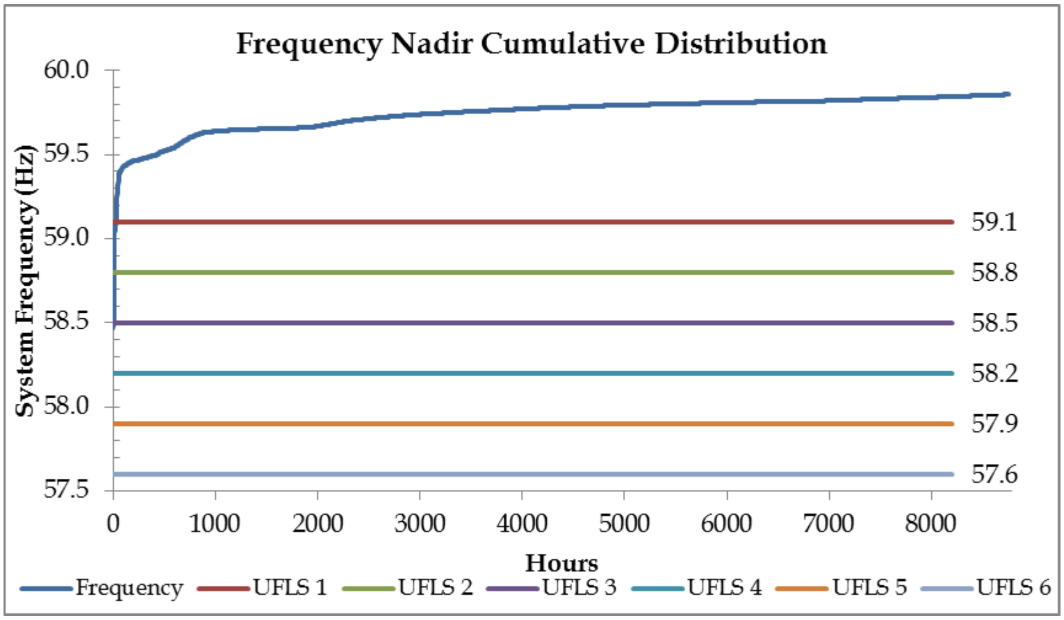

Figure O-380. Frequency Nadir Duration Curve 2030

Figure O-380 shows the frequency nadir duration curve for the Theme 3 resource plan in 2030. The system is at risk of exceeding the UFLS requirements of TPL-001 for 4 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Tuesday 4/30/30 Hour 6		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	26.4	2.1	17.4
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Geo2	20.0		5.00	40.0	200	20.0	0.0	20.0
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	4.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.5		
Apollo	20.5	0.0				6.7		
HRD	10.5	0.0				0.8		
Wind1	20.0	0.0				4.0		
Wind2	20.0	0.0				4.0		
Hydro	16.8	0				5		
Wind	31.0	0				16		
DG-PV	154.3	0						
Total Kinetic Energy						794		
Total Load						123		
Total Thermal Generation						103		
Total Renewable Generation						20		
Total Storage						0		
Total Generation						123		
Excess Generation						0		
Total Up Regulation						4		
Total Down Regulation						72		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-168. Unit Commitment and Dispatch 2030

Table O-168 shows the unit commitment and dispatch for the boundary hour (4/30/30, 6:00 AM).

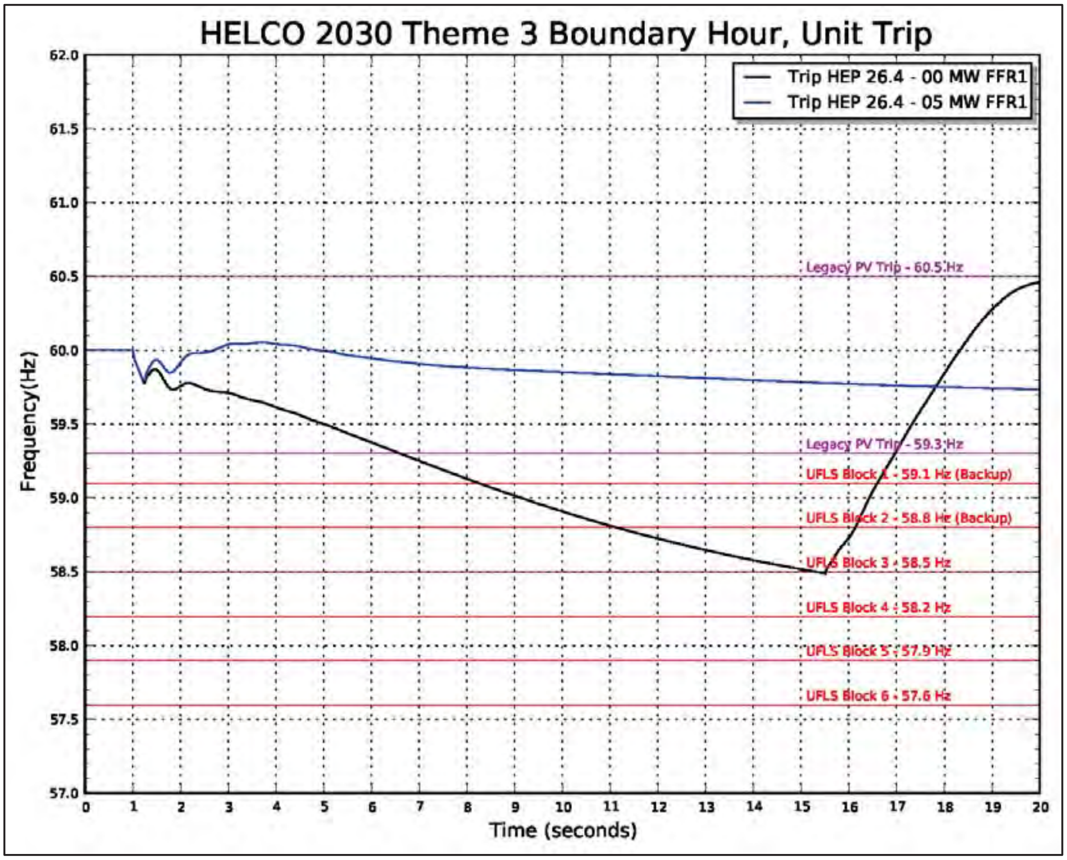

Figure O-381. Frequency Response Profile for FFR1 Boundary Hour

Figure O-381 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

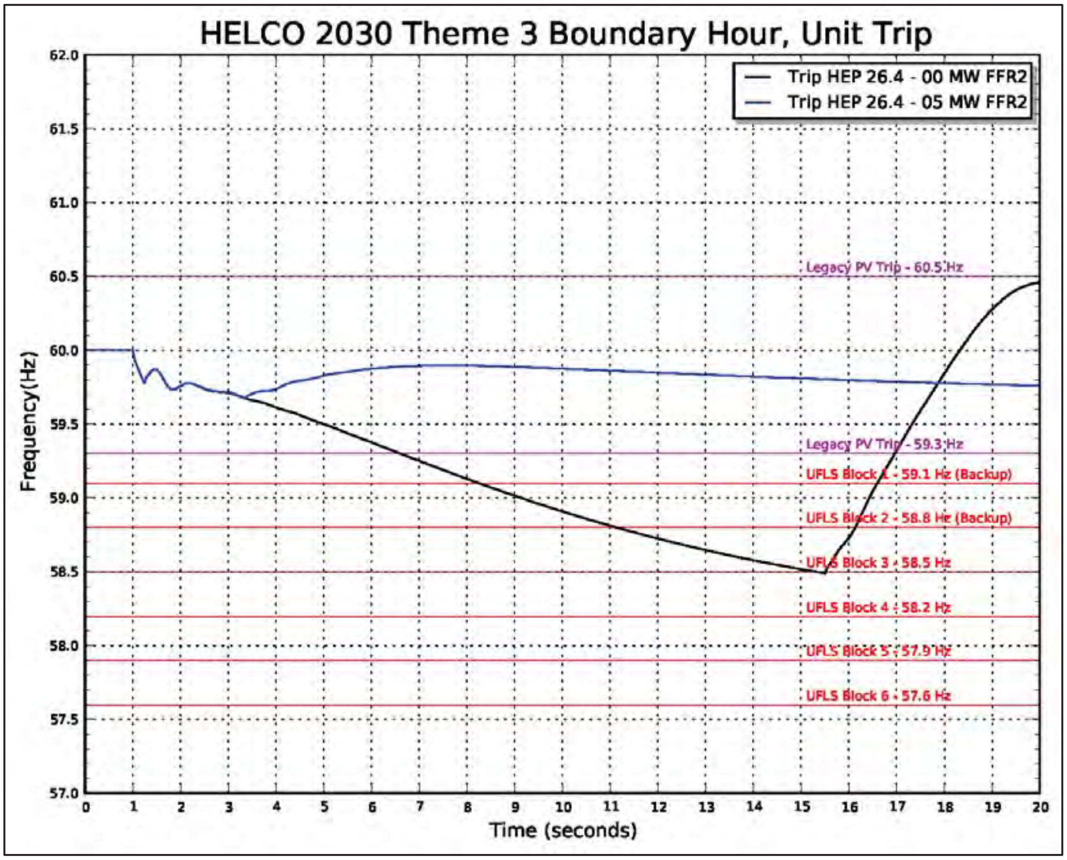

Figure O-382. Frequency Response Profile for FFR2 Boundary Hour

Figure O-382 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

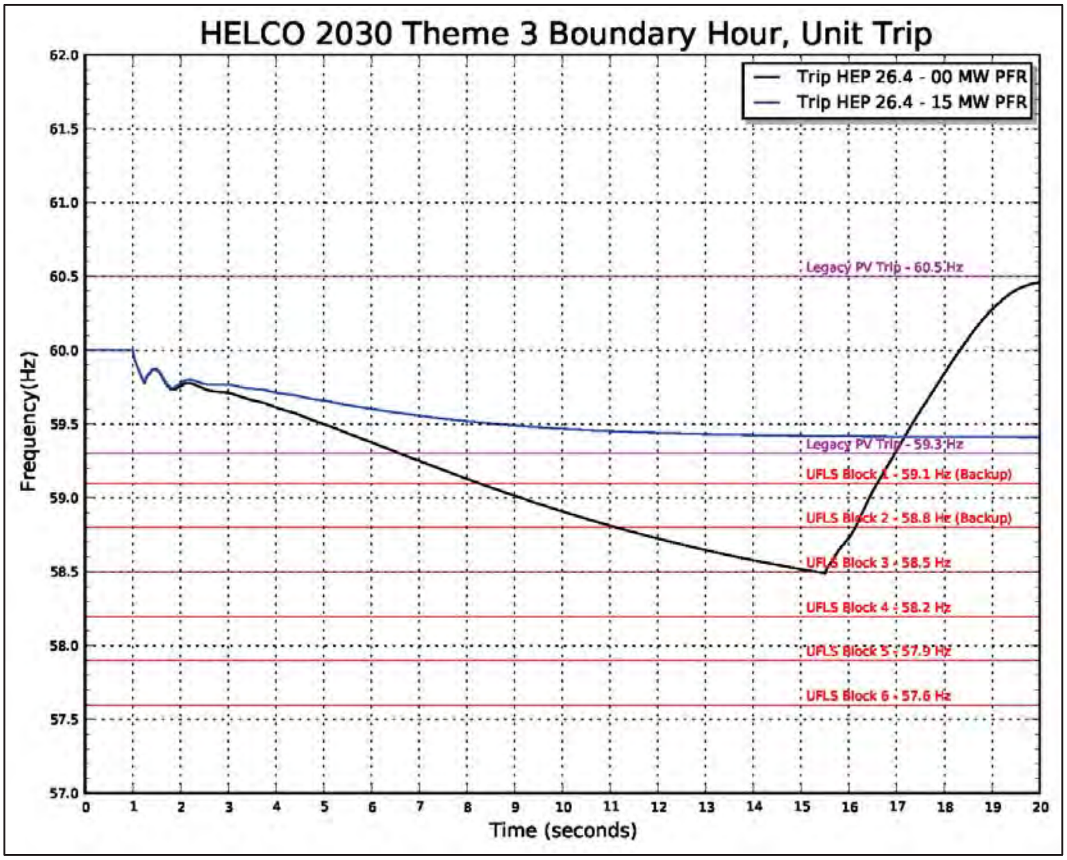

Figure O-383. Frequency Response Profile for PFR Boundary Hour

Figure O-383 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 15MW. This is in addition to the 4 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Wed 3/21/45 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.9	1.1	14.9
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	25.7	2.8	16.7
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Geo2	20.0		5.00	40.0	200			
Biomass1	20.0		3.16	28.0	88	18.0	2.0	18.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.1		
Apollo	20.5	0.0						
HRD	10.5	0.0				3.4		
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	31.0	0				3		
DG-PV	195.4	0						
Total Kinetic Energy							683	
Total Load							108	
Total Thermal Generation							101	
Total Renewable Generation							8	
Total Storage							0	
Total Generation							108	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							70	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-169. Unit Commitment and Dispatch 2045

Table O-169 shows the unit commitment and dispatch for the boundary hour (3/21/45, 4:00 AM).

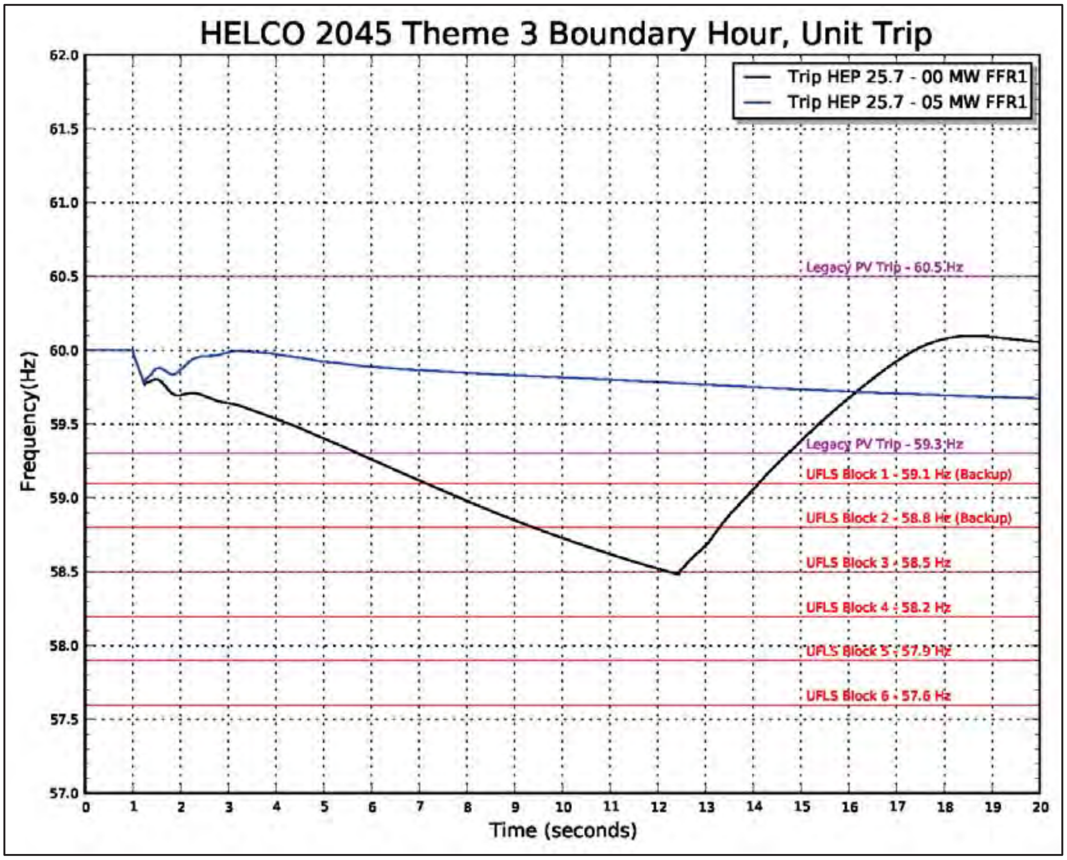

Figure O-384. Frequency Response Profile for FFR1 Boundary Hour

Figure O-384 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 683 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

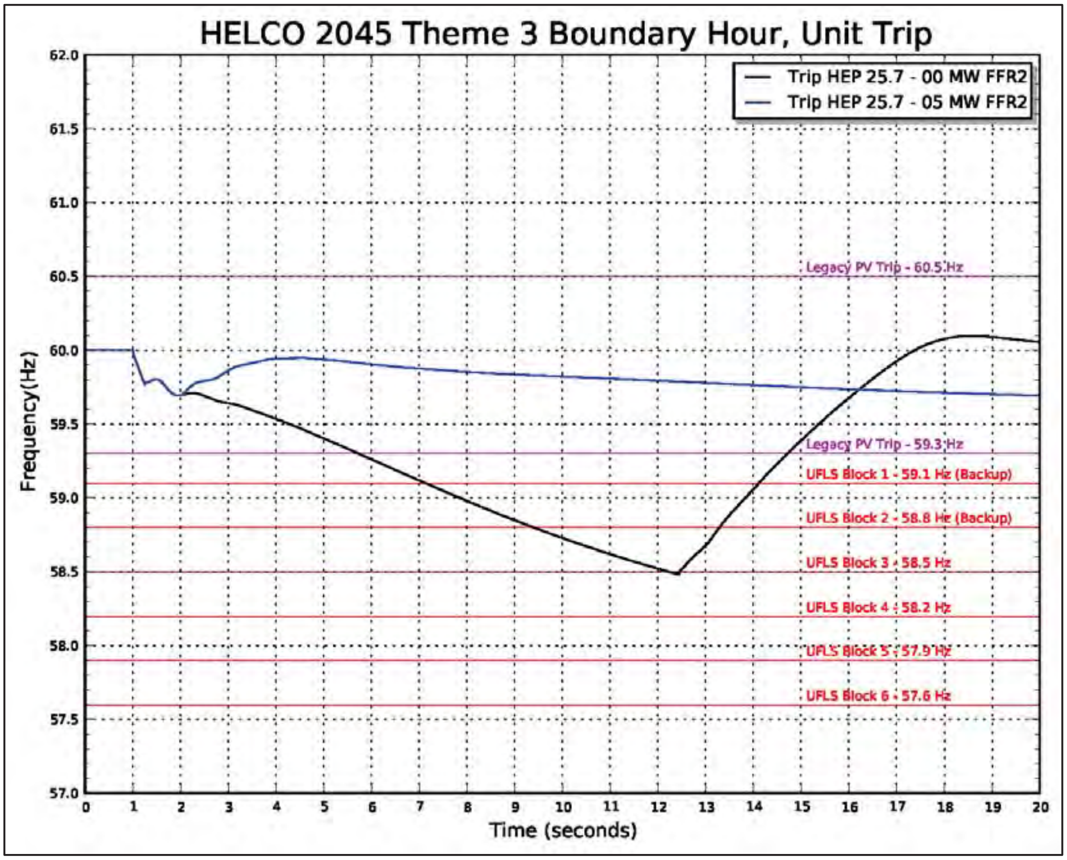

Figure O-385. Frequency Response Profile for FFR2 Boundary Hour

Figure O-385 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

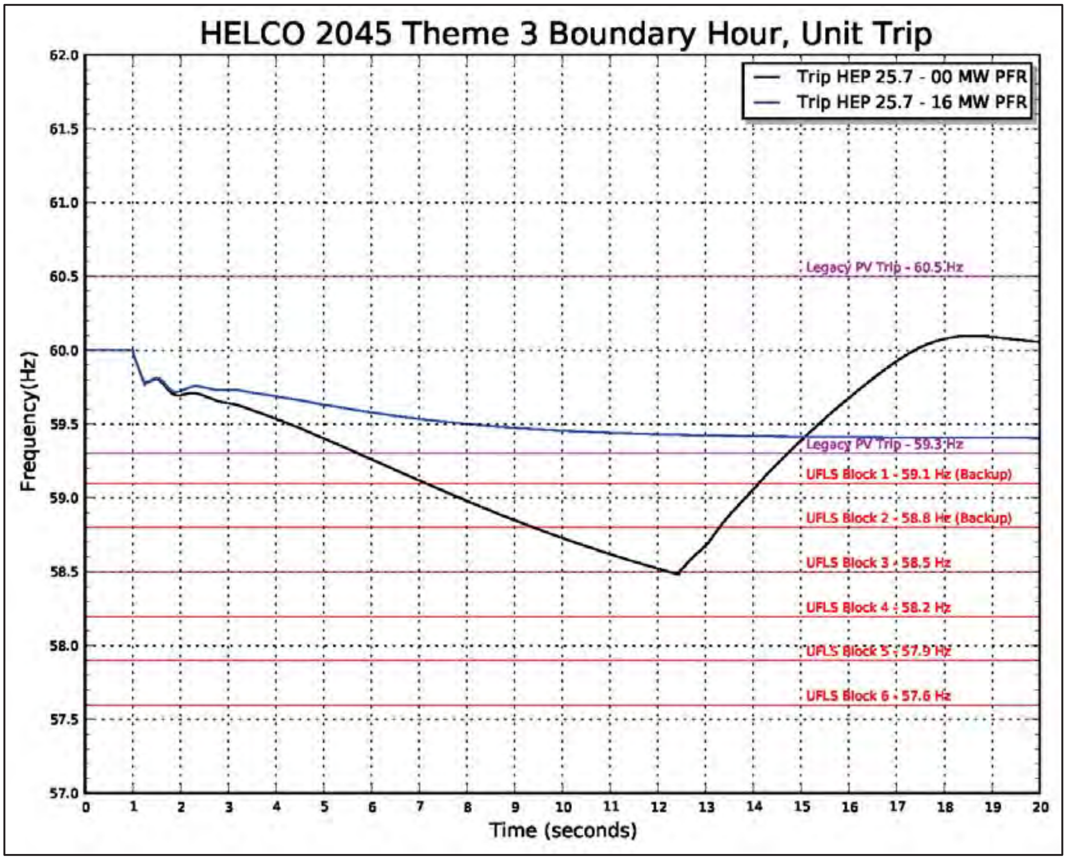

Figure O-386. Frequency Response Profile for PFR Boundary Hour

Figure O-386 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 16MW. This is in addition to the 6 MW of upward regulation from thermal generation.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021. Hawaiʻi does not have FFR2 capacities in their Demand Response portfolio.

2019

System security analysis performed on the Post April DR resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Hawaiʻi transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirement of 80 MVA on the 69 kV transmission system of which 25 MVA must be connected on the West side of the island. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai‘i, the critical busses with the highest MVAR demand are the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR- QV Dispatch Wed 9/25/19 Hour 22		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.0	5.0	11.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	17.3	3.2	9.3
Puna	15.5	6.0	4.63	18.8	87	12.0	3.5	6.0
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	11.7	8.3	4.7
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				1.8		
HRD	10.5	0.0				1.9		
Hydro	16.8	0				2		
Wind	91.0	0				4		
DG-PV	117.7	0						
Total Kinetic Energy						651		
Total Load						138		
Total Thermal Generation						132		
Total Renewable Generation						6		
Total Storage						0		
Total Generation						138		
Excess Generation						0		
Total Up Regulation						22		
Total Down Regulation						71		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-170. Unit Commitment and Dispatch 2019 QV Analysis

Table O-170 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR- QV MVAR Capability Wed 9/25/19 Hour 22		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	31.6	-20.1	-2.3	33.9	-17.9
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-3.1	51.1	-25.0
Hill 5	6.1	-5.5			
Hill 6	14.7	-12.4	-3.0	17.7	-9.4
Puna	11.0	-7.9	2.1	8.9	-10.1
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	17.3	-12.1	3.4	13.9	-15.4
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-0.2	5.4	-9.9
HRD	4.0	-4.0	-1.6	5.6	-2.4
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			-2.8		
Total Renewable MVAR Generation			-1.8		
Total Cap Bank MVAR			49.6		
Charging MVAR			16.2		
Total MVAR Supply			61.1		
Total MVAR Load			32.3		
Total MVAR Losses			28.7		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				136	
Total MVAR Absorb Capability					-90.1

Table O-171. MVAR Capability 2019 QV Analysis

Table O-171 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
35	L7700 Haina-Waimea
36	L7700 Haina
50	L8600 Kahaluu

Table O-172. N-1 Contingencies 2019 QV Analysis

Table O-172 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

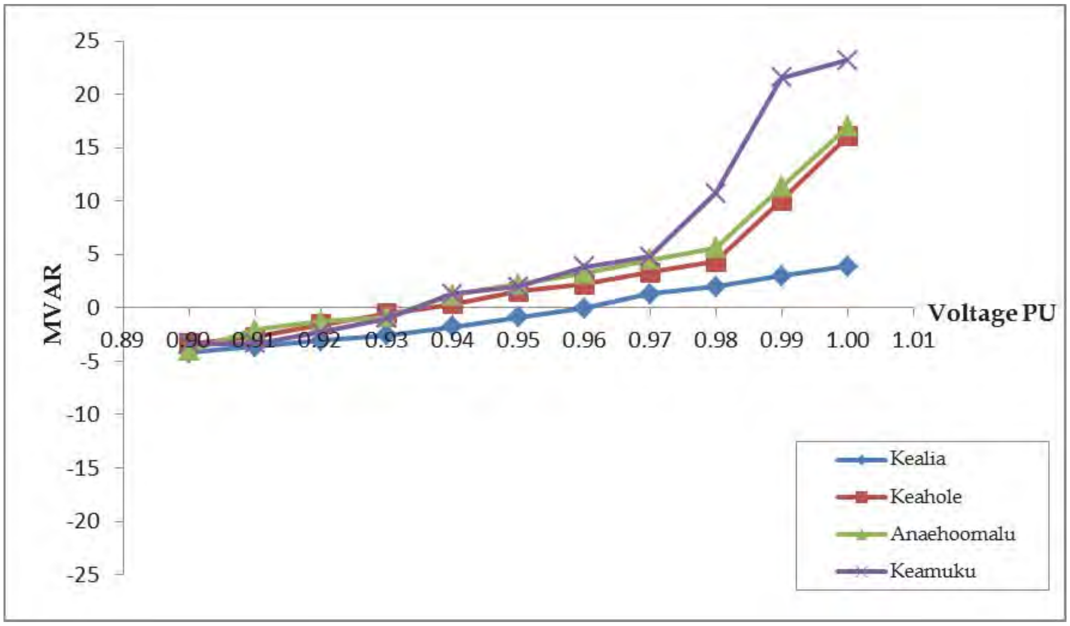

Figure O-387. QV Curves 2019

Figure O-387 shows the QV curves for the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The Anaeho‘omalu, Keahole, and Keamuku busses require 2 MVAR to maintain bus voltage at 0.95 PU. For the purpose of this analysis, the reactive power requirements of the system are met.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	4	36	3	36	2	36	1	36	0	36	-1	36	-2	50	-3	50	-3	50	-4	50	-4
8400	Keahole	36	16	36	10	36	4	36	3	36	2	36	2	36	0	36	-1	36	-2	36	-3	36	-3
8500	Anaehoomalu	35	17	36	11	36	6	36	4	36	3	36	2	36	1	36	-1	36	-1	36	-2	36	-4
8700	Keamuku	36	23	36	22	36	11	36	5	36	4	36	2	36	1	36	-1	36	-2	36	-3	36	-3

Table O-173. Summary of Results 2019 QV Analysis

Table O-173 shows the results of the QV analysis with the additional synchronous condensers. The Anaehoʻomalu and Keamuku busses require 2 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

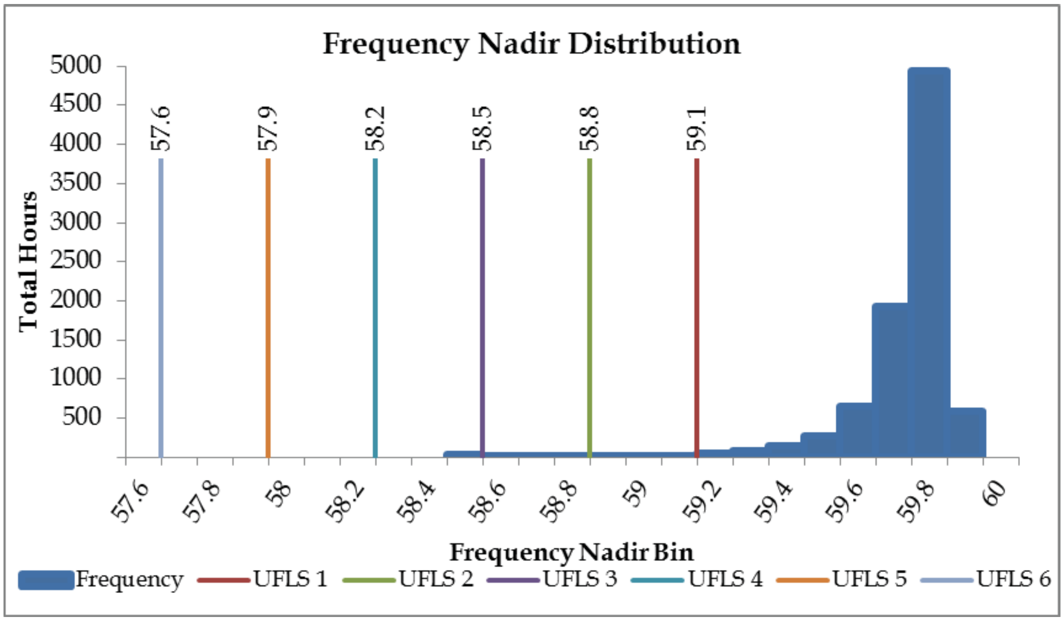

Figure O-388. Frequency Nadir Histogram for 2019

Figure O-388 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Post April DR production cost simulations. The boundary hour selected from a maximum distribution of 35 hours was 1:00 AM on Sunday, September 15. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

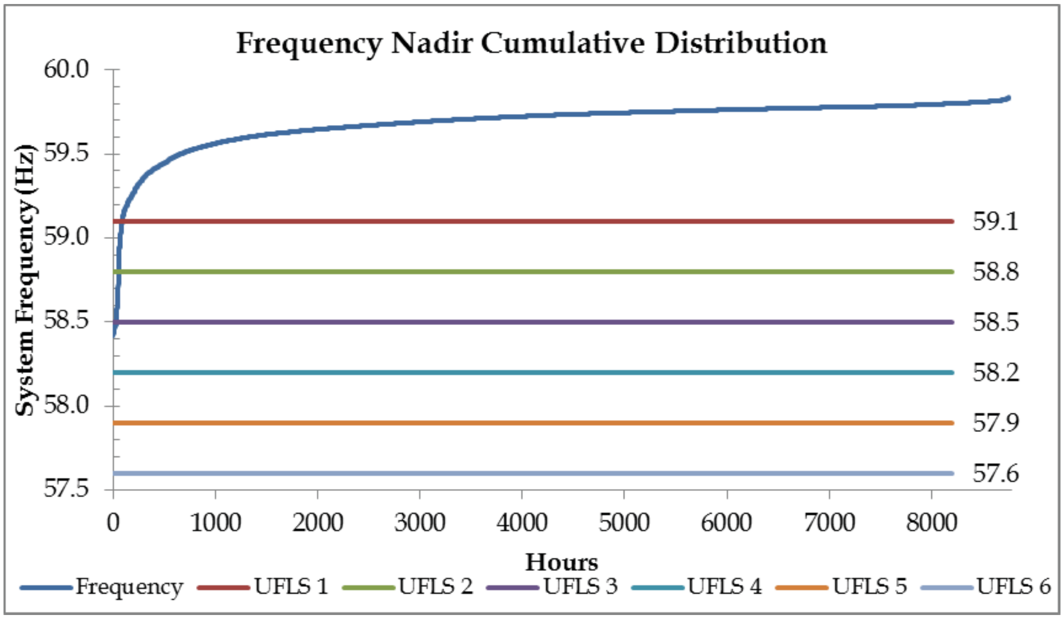

Figure O-389. Frequency Nadir Duration Curve 2019

Figure O-389 shows the frequency nadir duration curve for the Post April DR resource plan in 2019. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 35 hours of the year.

Unit	Unit Ratings					DR - HEP Trip Boundary Sun 9/15/19 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146	24.3	0.7	17.3
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	15.1	5.4	7.1
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0						
HRD	10.5	0.0				0.3		
Hydro	16.8	0				2		
Wind	91.0	0				0		
DG-PV	117.7	0						
Total Kinetic Energy							511	
Total Load							109	
Total Thermal Generation							106	
Total Renewable Generation							2	
Total Storage							0	
Total Generation							109	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							40	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-174. Unit Commitment and Dispatch 2019

Table O-174 shows the unit commitment and dispatch for the typical hour (9/15/19, 1:00 AM).

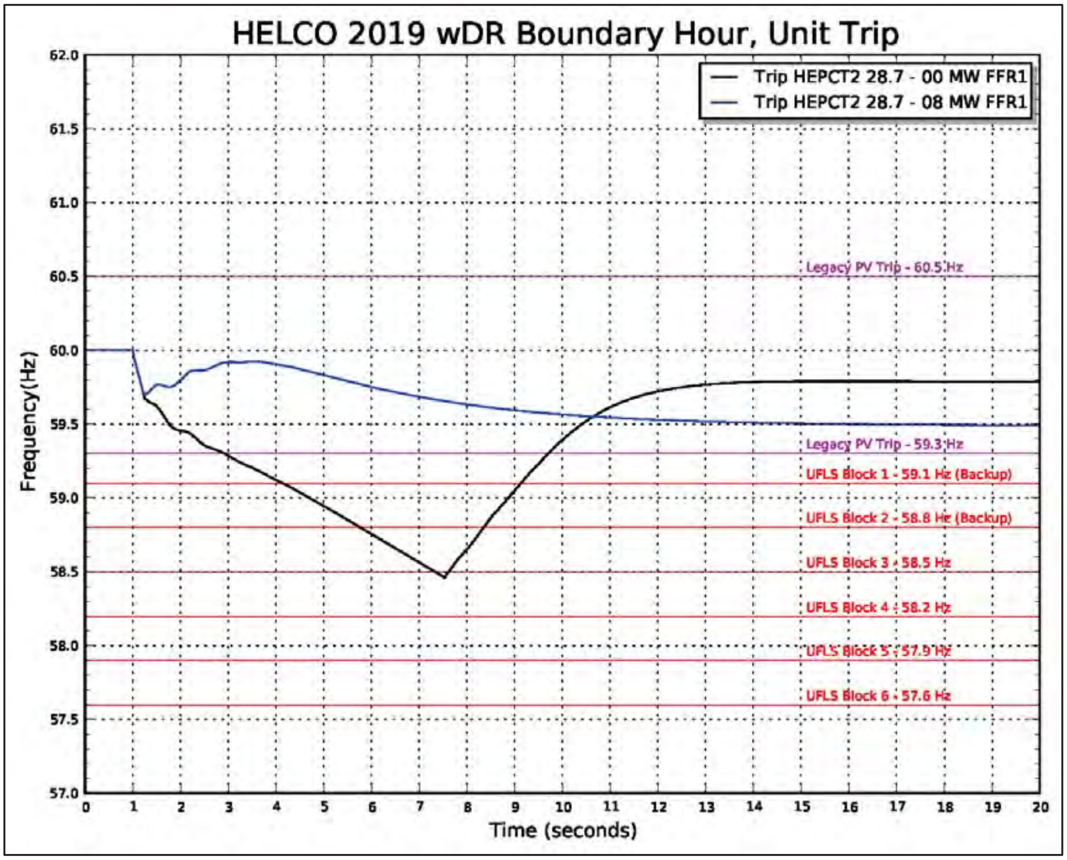

Figure O-390. Frequency Response Profile for FFR1 Boundary Hour

Figure O-390 shows the frequency response profile for a HEP CT2 trip at 28.7 MW. System kinetic energy is 511 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

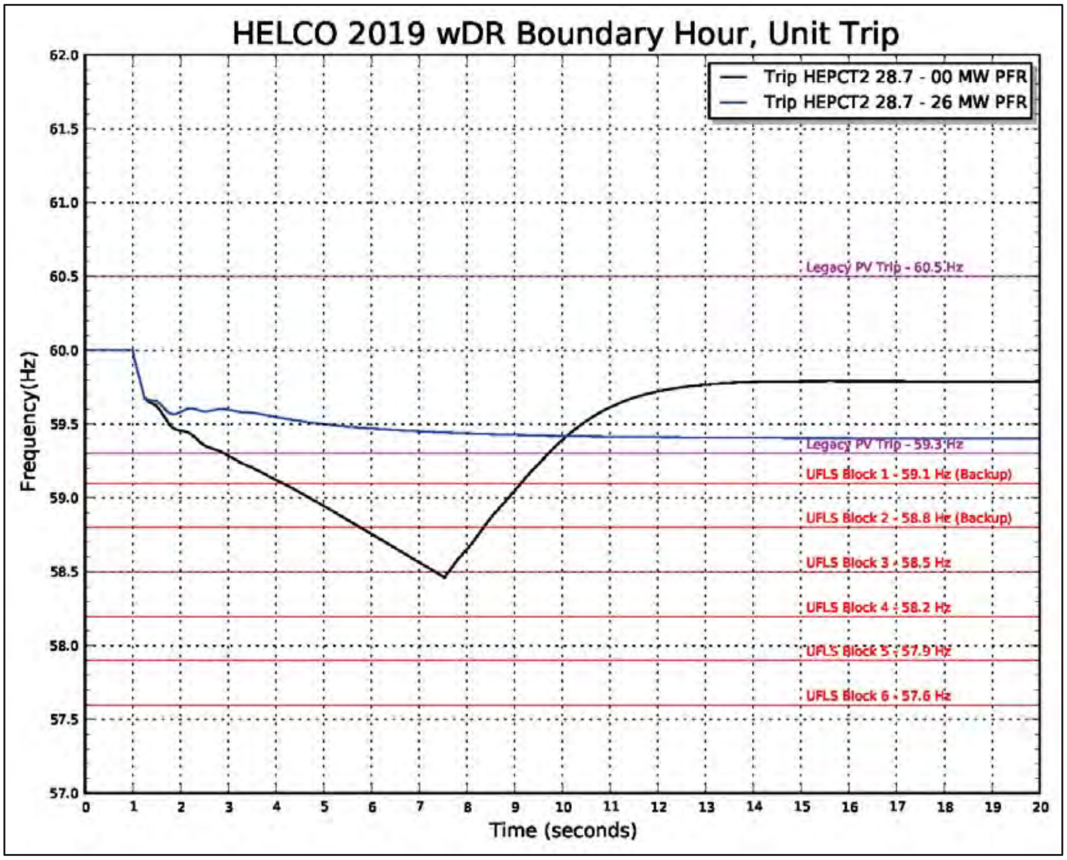

Figure O-391. Frequency Response Profile for PFR Boundary Hour

Figure O-391 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 26 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Sun 4/14/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	7.0	13.0	0.0
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	15.8	12.7	6.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	5.0	8.5	0.0
Hill 6	20.5	8.0	2.53	27.5	70	13.3	7.2	5.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.6		
Apollo	20.5	0.0				20.5		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				4		
Wind	91.0	0				31		
DG-PV	117.7	0				71		
Total Kinetic Energy						377		
Total Load						148		
Total Thermal Generation						41		
Total Renewable Generation						107		
Total Storage						0		
Total Generation						148		
Excess Generation						0		
Total Up Regulation						41		
Total Down Regulation						12		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.9
	60.5Hz Capacity			56.6		60.5Hz Output		35.0

Table O-175. Unit Commitment and Dispatch Fault Analysis

Table O-175 shows the unit commitment and dispatch for the 69 kV fault analysis (4/14/19, 1:00 PM).

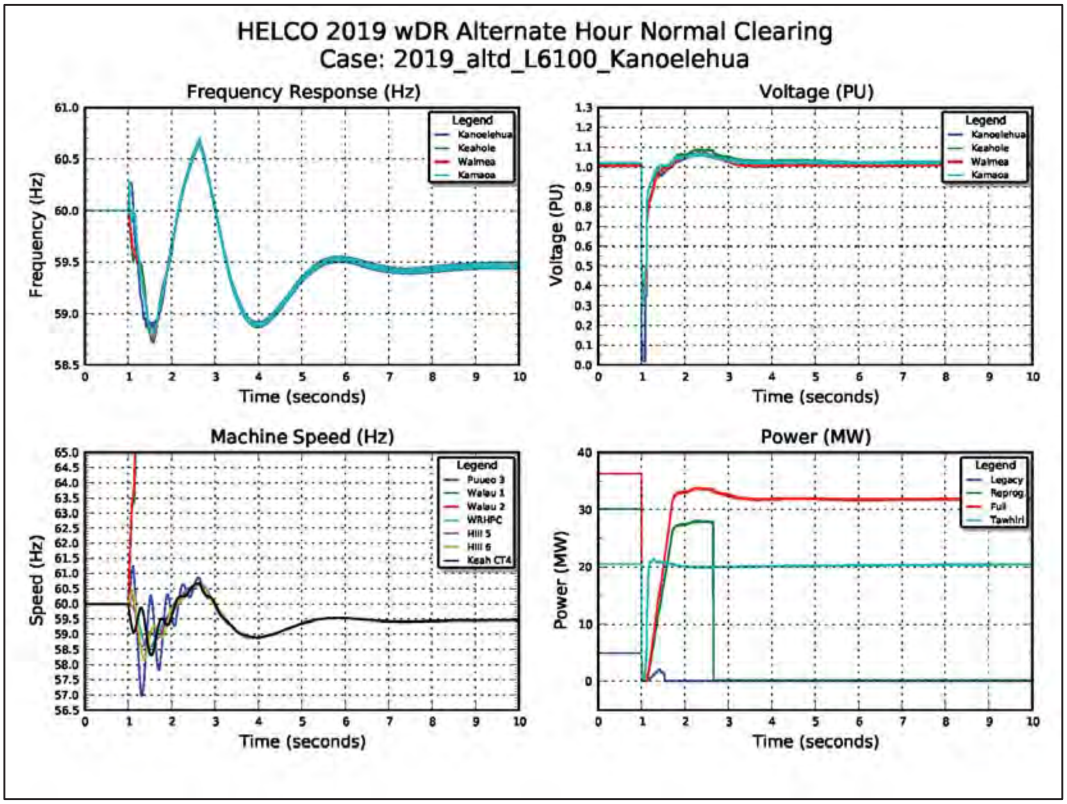

Figure O-392. System Performance Normally Cleared

Figure O-392 shows the system performance for a normally cleared fault on the on the L6100 circuit near the Kanoelehua Substation. Waiau Units 1 and 2 lose synchronism with the system almost immediately after the fault, indicating the normal clearing time exceeds the critical clearing time for stability.

Sensitivity analyses were performed with synchronous condensers and a BESS but the system remains unstable for normally cleared faults on multiple circuits with this unit commitment and dispatch schedule.

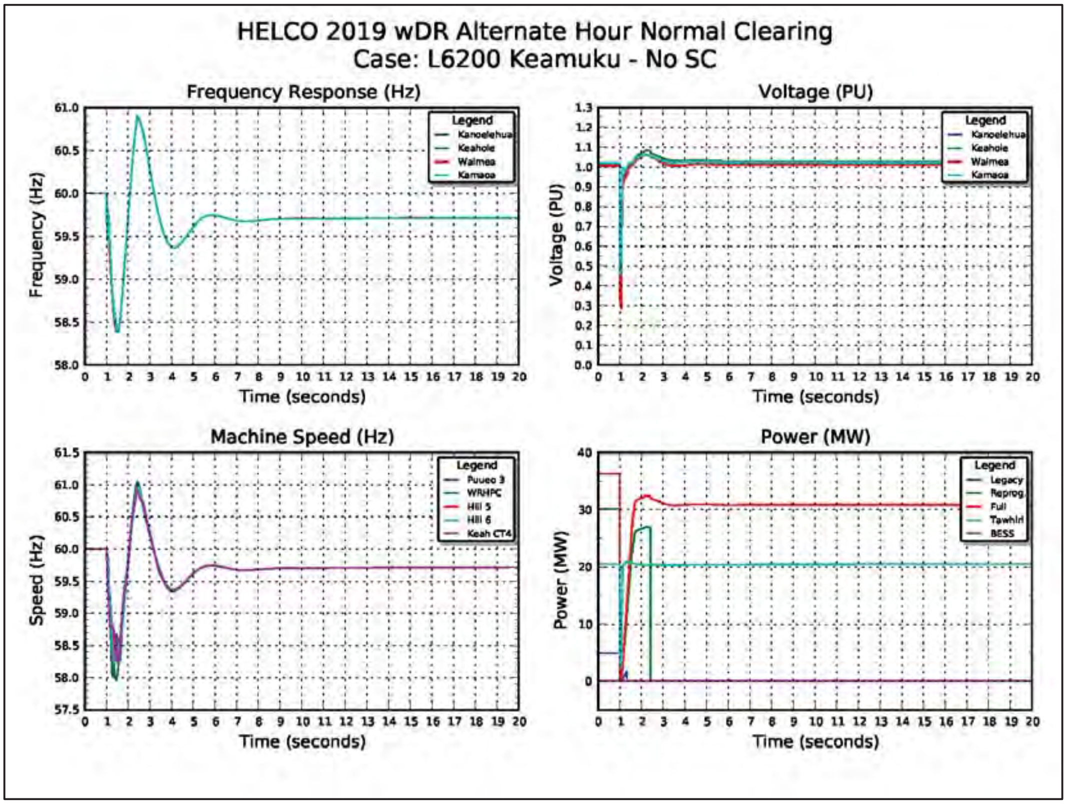

Figure O-393. System Performance Normally Cleared Fault

Figure O-393 shows the system performance for a normally cleared fault on the on the L6200 circuit near the Keamuku Substation. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 71 MW from the system. System frequency decays while system voltage recovers when the fault is cleared, restoring generation from some DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, as-available generation, and three blocks of UFLS is able to stabilize system frequency at 58.4 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001 and/or improve the stability margin of the system. The analysis was performed for the L6200 circuit only.

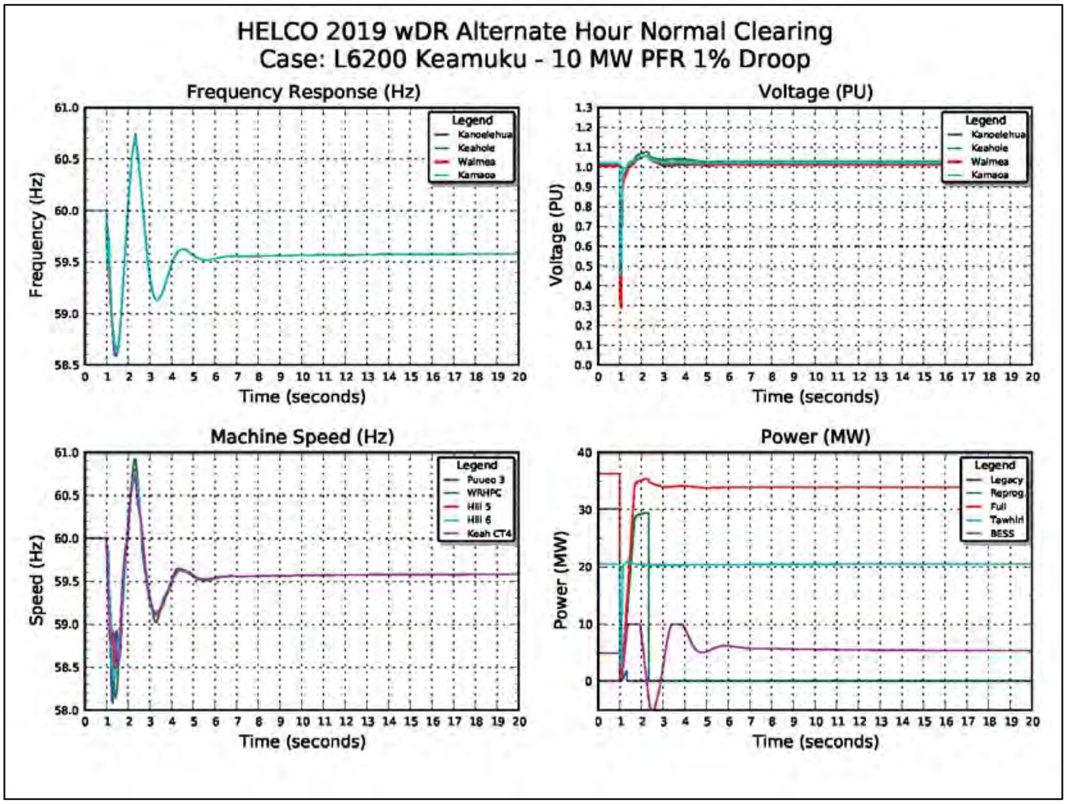

Figure O-394. Normally Cleared Fault Sensitivity 10 MW PFR

Figure O-394 shows system performance with the addition of 10 MW PFR at 1% droop response. For the purpose of this analysis, a 10 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 10 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2019 69kV Fault Normal Clearing Analysis				
Line No Outage	**3-phase Fault Near**	**System Status**	**Mitgation - Synchronous Condenser**	**Mitigaction - BESS**
L6100	Kanoelehua	Unstable	Unstable	Unstable
	Kaumana	Unstable	Unstable	Unstable
L6200	Kaumana	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L6300	Kilauea	Stable	Stable	Stable
	Puna	Stable	Stable	Stable
L6400	Kanoelehua	Unstable	Unstable	Unstable
	Puna	Unstable	Unstable	Unstable
L6500	Kaumana	Unstable	Stable	Unstable
	Pohoiki	Stable	Stable	Stable
L6600	Kamaoa	Stable	Stable	Stable
	Kilauea	Stable	Stable	Stable
L6700	Kahaluu	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L6800	Keahole	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L7100	Anaehoomalu	Stable	Stable	Stable
	Poopoomino	Stable	Stable	Stable
L7200	Keamuku	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7300	Ouli	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7400	Pepeekeo	Unstable	Unstable	Unstable
	Wailuku	Unstable	Unstable	Unstable
L7500	Kailua	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L7600	Honokaa	Stable	Stable	Stable
	Pepeekeo	Stable	Stable	Stable
L7700	Haina	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable	Unstable
	Puueo	Unstable	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L8200	Anaehoomalu	Stable	Stable	Stable
	Mauna Lani	Stable	Stable	Stable
L8300	Mauna Lani	Stable	Stable	Stable
	Ouli	Stable	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable	Unstable
	Puueo	Unstable	Unstable	Unstable
L8500	Kaumana	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L8600	Kahaluu	Stable	Stable	Stable
	Kealia	Stable	Stable	Stable
L8700	Pohoiki	Stable	Stable	Stable
	Puna	Stable	Stable	Stable
L8800	Haina	Stable	Stable	Stable
	Honokaa	Stable	Stable	Stable
L9100	Keahole	Stable	Stable	Stable
	Poopoomino	Stable	Stable	Stable
L9200	Kaumana	Unstable	Unstable	Unstable
	Wailuku	Unstable	Unstable	Unstable
L9300	Kailua	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L9500	Kahaluu	Stable	Stable	Stable
	Kailua	Stable	Stable	Stable
L9600	Kamaoa	Stable	Stable	Stable
	Kealia	Stable	Stable	Stable

Table O-176. Summary of Results Normal Clearing Fault Analysis

Table O-176 shows the results of the analysis for normally cleared faults. Thirteen simulations resulted in system instability because Waiau 1 loses synchronism with this unit commitment and dispatch schedule. Further analysis is required to determine if out-of-step protection is required.

The system requires 10 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai‘i, the critical busses with the highest MVAR demand are the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Dispatch Tue 2/25/20 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34	9.7	3.8	4.7
Hill 6	20.5	8.0	2.53	27.5	70	16.3	4.2	8.3
Puna	15.5	6.0	4.63	18.8	87	11.3	4.2	5.3
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	12.9	7.1	5.9
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.1		
Apollo	20.5	0.0				1.3		
HRD	10.5	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				1		
DG-PV	122.2	0						
Total Kinetic Energy						715		
Total Load						161		
Total Thermal Generation						146		
Total Renewable Generation						15		
Total Storage						0		
Total Generation						161		
Excess Generation						0		
Total Up Regulation						21		
Total Down Regulation						80		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-177. Unit Commitment and Dispatch 2020 QV Analysis

Table O-177 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR- QV MVAR Capability Tue 2/25/20 Hour 20		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	29.8	-19.3	-2.6	32.3	-16.7
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-3.5	51.6	-24.6
Hill 5	9.8	-7.9	-1.6	11.4	-6.3
Hill 6	15.1	-12.7	-2.8	17.9	-9.9
Puna	11.4	-8.2	1.9	9.5	-10.1
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	17.1	-11.8	3.0	14.1	-14.8
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-0.7	5.9	-9.4
HRD	4.0	-4.0	0.3	3.7	-4.3
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			-5.6		
Total Renewable MVAR Generation			-0.5		
Total Cap Bank MVAR			67.9		
Charging MVAR			16.2		
Total MVAR Supply			78.0		
Total MVAR Load			38.8		
Total MVAR Losses			39.2		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				146	
Total MVAR Absorb Capability					-96.2

Table O-178. MVAR Capability 2020 QV Analysis

Table O-178 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina

Table O-179. N-1 Contingencies 2020 QV Analysis

Table O-179 shows the N-1 contingency that has the greatest impact to MVAR requirements for the critical busses.

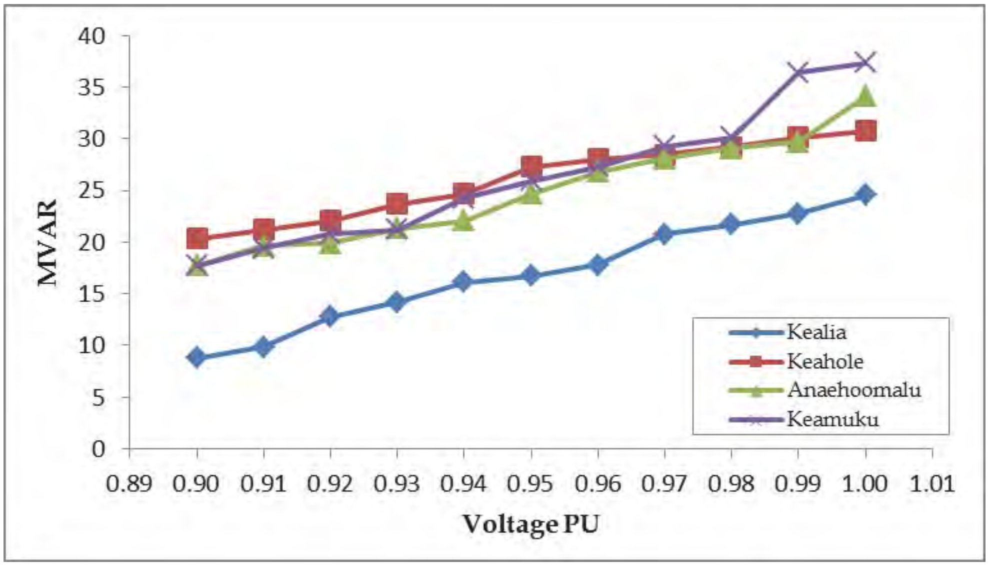

Figure O-395. QV Curves

Figure O-395 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the worst-case N-1 contingency event. All critical busses require additional reactive power with the highest demand from the Keahole bus at 27 MVAR. The system has 146 MVAR of reserve capacity but all of these resources are on the east side of the island, far away from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	25	36	23	36	22	36	21	36	18	36	17	36	16	36	14	36	13	36	10	36	9
8400	Keahole	36	31	36	30	36	29	36	28	36	28	36	27	36	25	36	24	36	22	36	21	36	20
8500	Anaehoomalu	36	34	36	30	36	29	36	28	36	27	36	25	36	22	36	21	36	20	36	20	36	18
8700	Keamuku	36	37	36	36	36	30	36	29	36	27	36	26	36	24	36	21	36	21	36	19	36	18

Table O-180. Results 2019 QV Analysis

Table O-180 shows the summary of results for the 2020 QV analysis.

To mitigate the reactive power shortfall, 18.8 MVA synchronous condensers were added to the Keahole and Keamuku switching stations.

Con #	Contingency Description
23	L7100 Anaehoomalu-Poopoomino
36	L7700 Haina
50	L8600 Kahaluu

Table O-181. N-1 Contingencies 2020 QV Mitigation Analysis

Table O-181 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

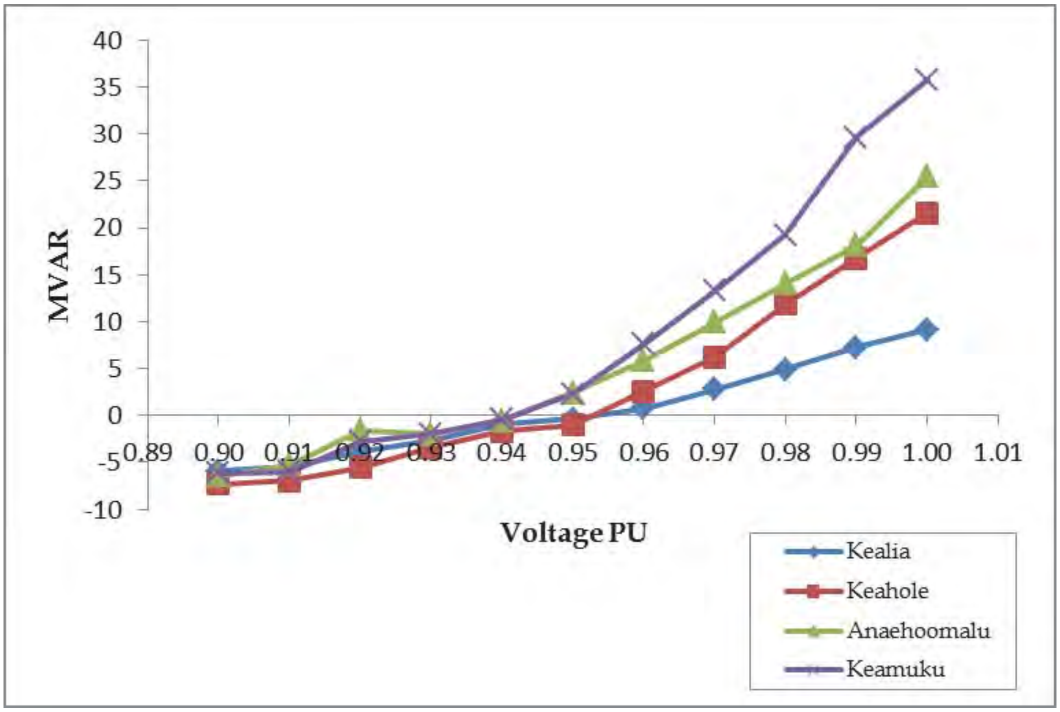

Figure O-396. QV Curves Synchronous Condensers

Figure O-396 shows the QV curves with 18.8 MVA synchronous condensers at Keahole and Keamuku switching stations.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																				
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	9	36	7	36	5	36	3	36	1	50	0	50	-1	50	-3	50	-4	50	-5	50	-6
8400	Keahole	36	22	36	17	36	12	36	6	36	3	36	-1	36	-2	36	-3	36	-6	36	-7	36	-7
8500	Anaehoomalu	36	25	36	18	36	14	36	10	36	6	36	2	36	0	36	-2	36	-2	36	-5	36	-6
8700	Keamuku	36	36	36	30	36	19	36	13	36	8	36	2	36	0	36	-2	36	-3	36	-6	36	-6

Table O-182. Summary of Results 2020 QV Mitigation Analysis

Table O-182 shows the results of the QV analysis with the additional synchronous condensers. The Anaeho'omalu and Keamuku busses require 2 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Under this contingency, L6200 is operating at 113% of its emergency rating which violates the transmission planning criteria. To mitigate the overload, the conductors for L6200 were increased from 336 AAC to 556 AAC to simulate a re-conductor project.

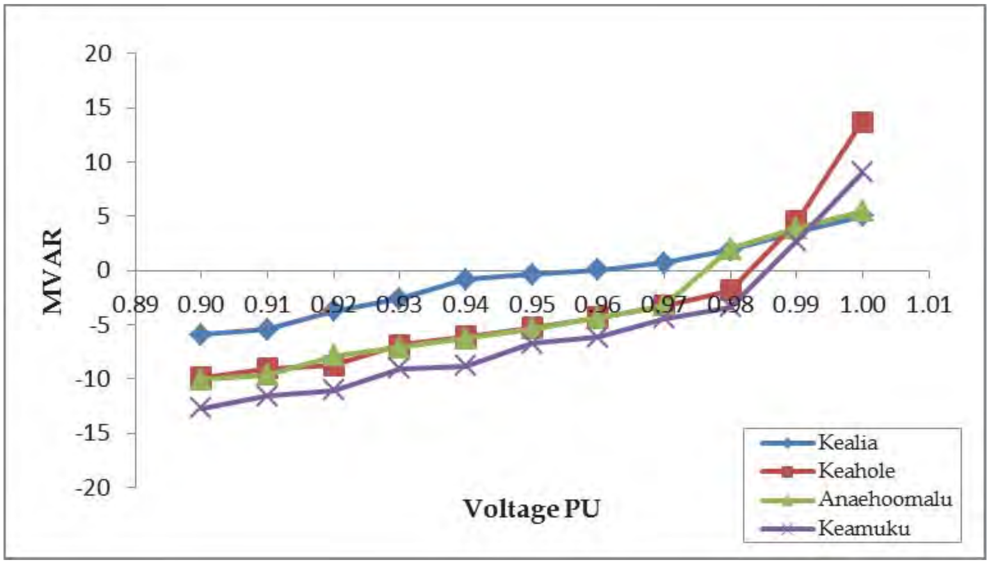

Figure O-397. QV Curves L6200 Reconductor

Figure O-397 shows the QV curves with the L6200 conductors increased from 336 AAC to 556 AAC.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	5	50	4	50	2	50	1	50	0	50	0	50	-1	50	-3	50	-4	50	-5	50	-6
8400	Keahole	36	14	23	5	23	-2	23	-3	36	-4	36	-5	36	-6	36	-7	36	-9	36	-9	36	-10
8500	Anaehoomalu	36	5	36	4	36	2	36	-3	36	-4	36	-5	36	-6	36	-7	36	-8	36	-10	36	-10
8700	Keamuku	36	9	36	3	36	-3	36	-4	36	-6	36	-7	36	-9	36	-9	36	-11	36	-12	36	-13

Table O-183. Summary of Results 2020 QV Analysis L6200 Reconductor

Table O-183 shows the results for the QV analysis with the L6200 conductors increased from 336 AAC to 556 AAC. Increasing the ampacity of L6200 eliminates the overload condition and meets the reactive power requirements of the system. No additional synchronous condensers are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

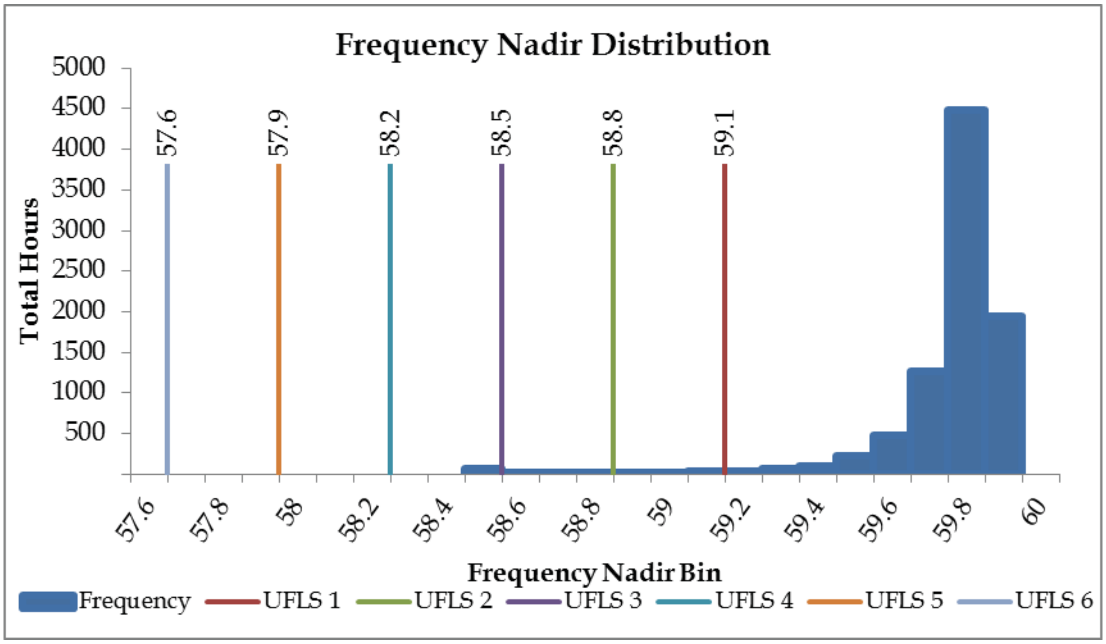

Figure O-398. Frequency Nadir Histogram 2020

Figure O-398 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 71 hours was 3:00 AM on Tuesday, November 10. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

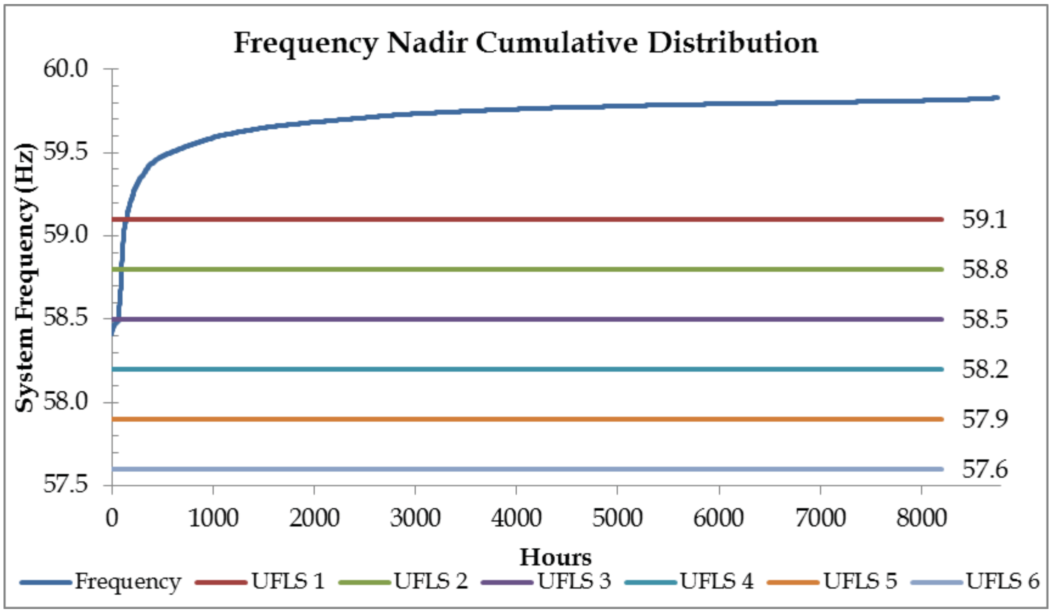

Figure O-399. Frequency Nadir Duration Curve 2020

Figure O-399 shows the frequency nadir duration curve for the Post April DR resource plan in 2020. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Tue 11/10/20 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	15.0	5.5	7.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2	2.5	0.0	1.7
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.1		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				10		
Wind	91.0	0				0		
DG-PV	122.2	0						
Total Kinetic Energy						466		
Total Load						94		
Total Thermal Generation						84		
Total Renewable Generation						10		
Total Storage						0		
Total Generation						94		
Excess Generation						0		
Total Up Regulation						6		
Total Down Regulation						25		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-184. Unit Commitment and Dispatch 2020

Table O-184 shows the unit commitment and dispatch for the typical hour (11/10/20, 3:00 AM).

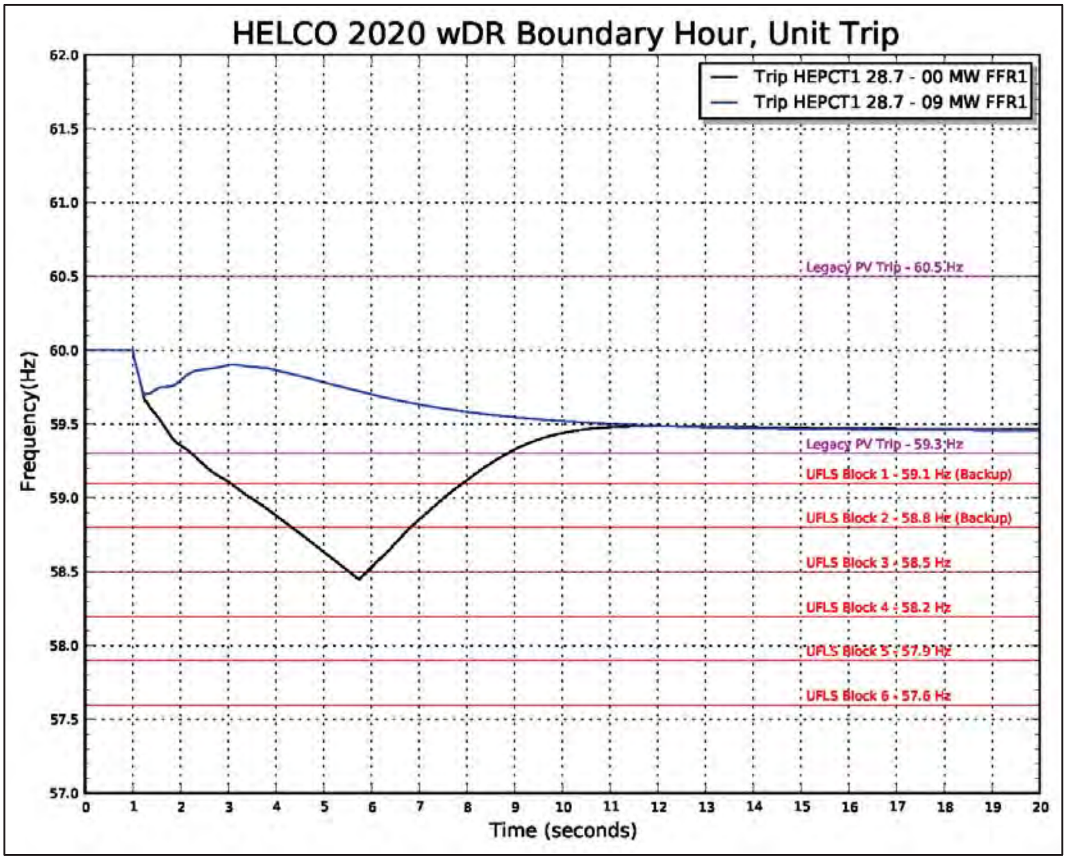

Figure O-400. Frequency Response Profile for FFR1 Boundary Hour

Figure O-400 shows the frequency response profile for a HEP CT2 trip at 28.7 MW. System kinetic energy is 466 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

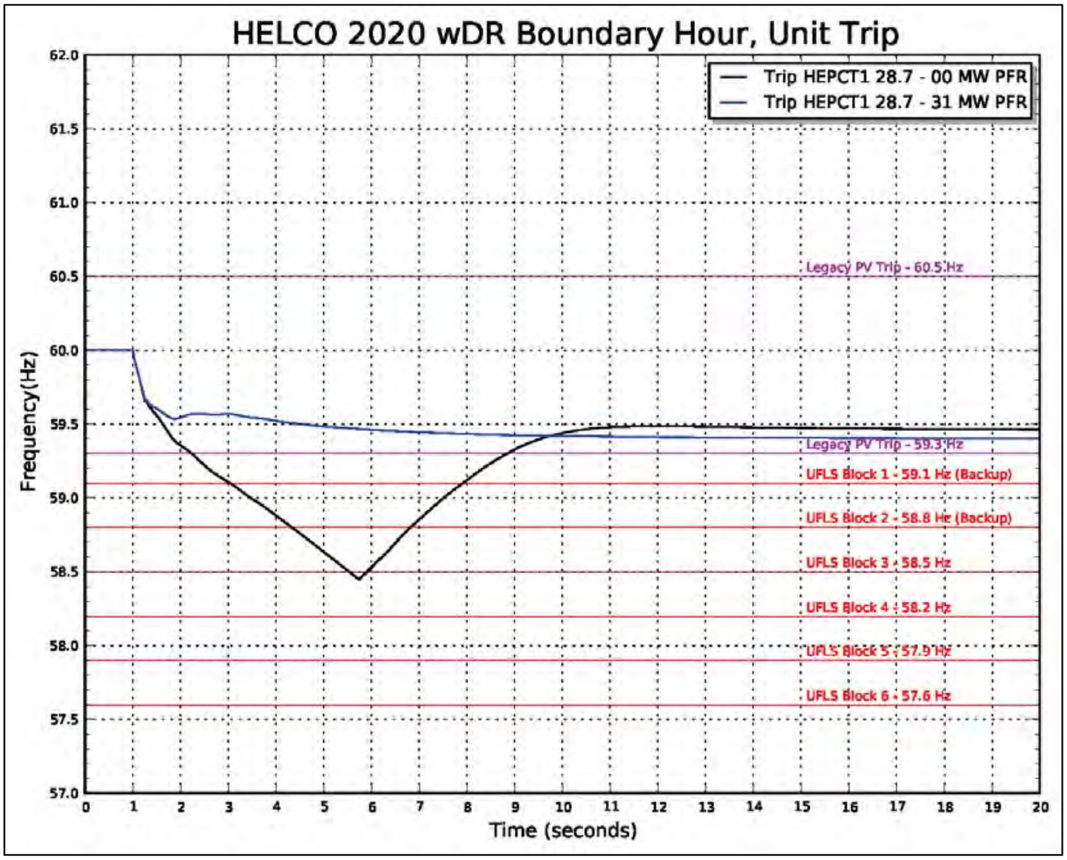

Figure O-401. Frequency Response Profile for PFR Typical Hour

Figure O-401shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 31 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Thu 2/27/20 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	20.0	40.0	1.5
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	8.0	12.5	0.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	10.3		
Apollo	20.5	0.0				19.6		
HRD	10.5	0.0				7.1		
Wind1	20.0	0.0				17.6		
Hydro	16.8	0				12		
Wind	91.0	0				44		
DG-PV	122.2	0				73		
Total Kinetic Energy							342	
Total Load							158	
Total Thermal Generation							28	
Total Renewable Generation							130	
Total Storage							0	
Total Generation							158	
Excess Generation							0	
Total Up Regulation							52	
Total Down Regulation							2	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.8
	60.5Hz Capacity			56.6		60.5Hz Output		34.4

Table O-185. Unit Commitment and Dispatch Fault Analysis

Table O-185 shows the unit commitment and dispatch for the 69 kV fault analysis (2/27/20, 2:00 PM).

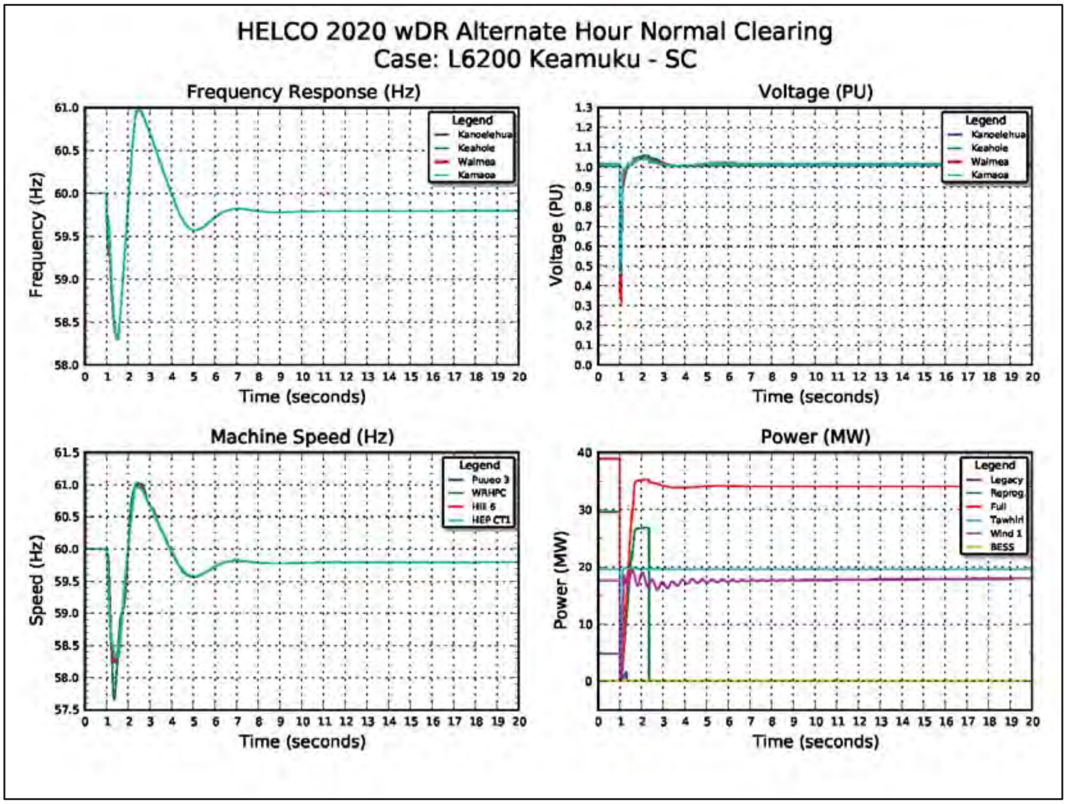

Figure O-402. System Performance Normally Cleared Fault

Figure O-402 shows the system performance for a normally cleared fault on the L6200 circuit near the Keamuku Substation. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 71 MW from the system. System frequency decays while system voltage recovers when the fault is cleared, restoring generation from some DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, as-available generation, and three blocks of UFLS is able to stabilize system frequency at 58.4 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to improve system security. Results will vary for different circuits and dispatch schedules.

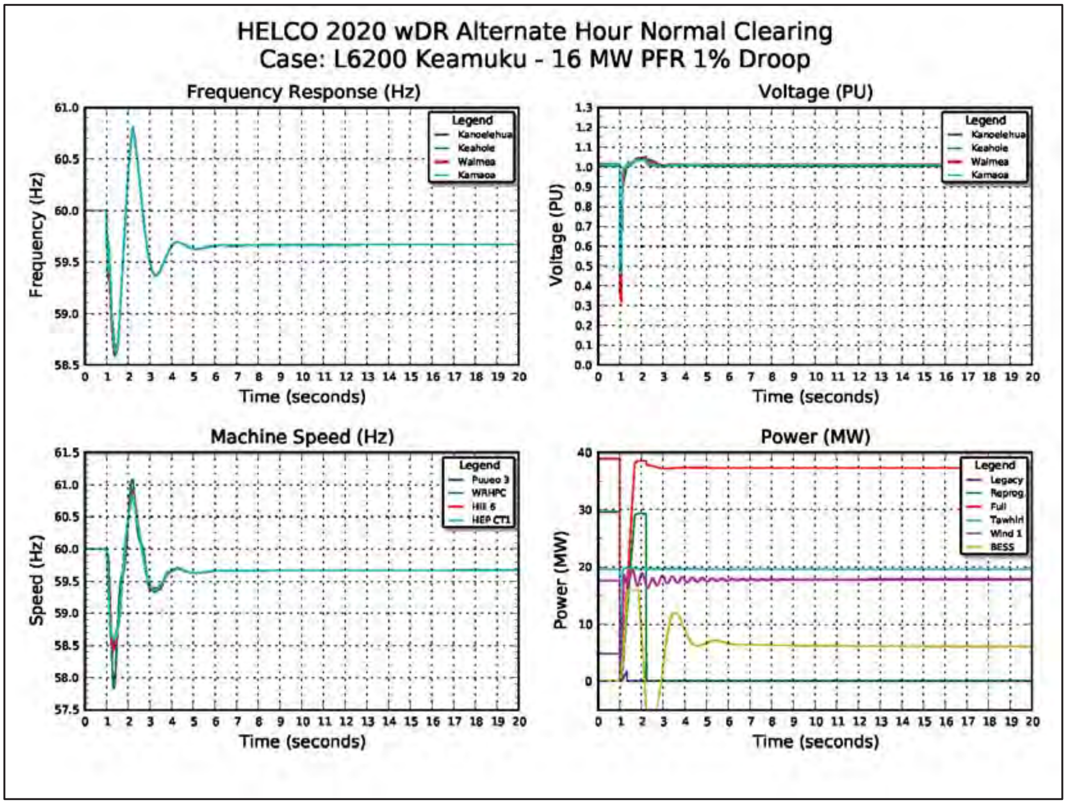

Figure O-403. Normally Cleared Fault Sensitivity 16 MW PFR

Figure O-403 shows system performance with the addition of 16 MW PFR at 1% droop response. For the purpose of this analysis, a 16 MW BESS was located at the Anaeho'omalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 10 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai‘i, the critical busses with the highest MVAR demand are the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Dispatch Mon 11/8/21 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34	9.1	4.4	4.1
Hill 6	20.5	8.0	2.53	27.5	70	16.0	4.5	8.0
Puna	15.5	6.0	4.63	18.8	87	11.3	4.2	5.3
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	14.1	5.9	7.1
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	11.2		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				0		
DG-PV	126.0	0				18		
Total Kinetic Energy						715		
Total Load						178		
Total Thermal Generation						146		
Total Renewable Generation						32		
Total Storage						0		
Total Generation						178		
Excess Generation						0		
Total Up Regulation						21		
Total Down Regulation						80		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		1.2
	60.5Hz Capacity			56.6		60.5Hz Output		8.2

Table O-186. Unit Commitment and Dispatch 2021 QV Analysis

Table O-186 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Mon 11/8/21 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	29.8	-19.3	-6.1	35.8	-13.3
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-0.3	48.3	-27.8
Hill 5	10.0	-8.2	4.6	5.4	-12.8
Hill 6	15.3	-12.8	8.0	7.2	-20.9
Puna	11.4	-8.2	-0.4	11.8	-7.8
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	16.8	-11.6	-0.6	17.5	-11.0
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	3.0	1.0	-7.0
Wind1	6.6	-6.6			
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			5.3		
Total Renewable MVAR Generation			3.0		
Total Cap Bank MVAR			62.2		
Charging MVAR			16.2		
Total MVAR Supply			86.6		
Total MVAR Load			49.5		
Total MVAR Losses			38.2		
Excess MVAR Generation			-1.0		
Total MVAR Supply Capability				127	
Total MVAR Absorb Capability					-100.5

Table O-187. MVAR Capability 2021 QV Analysis

Table O-187 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
35	L7700 Haina-Waimea
36	L7700 Haina
37	L7700 Waimea

Table O-188. N-1 Contingencies 2021 QV Analysis

Table O-188 shows the N-1 contingencies that were simulated in the QV analysis. These contingencies have the greatest impact to MVAR requirements for the critical busses.

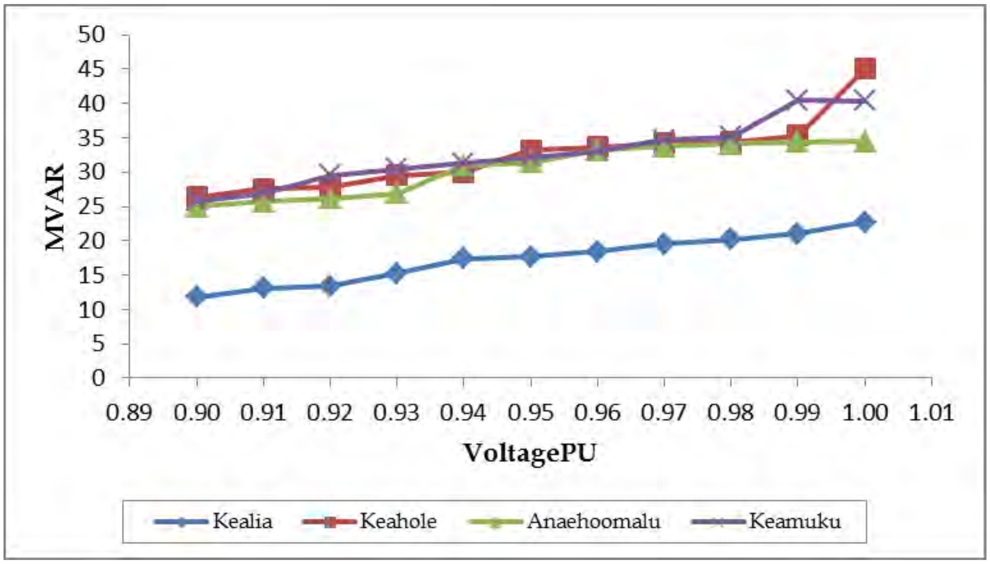

Figure O-404. QV Curves 2021

Figure O-404 shows the QV curves for the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. All critical busses require additional reactive power with the highest demand from the Keahole bus at 33 MVAR. The system has 127 MVAR of reserve capacity but all of these resources are on the east side of the island, far away from the load center.

Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
37	23	37	21	35	20	35	20	35	18	37	18	35	17	35	15	37	13	37	13	35	12
36	45	36	35	36	34	36	34	36	34	36	33	36	30	36	29	36	28	36	28	36	26
36	35	36	34	36	34	36	34	36	33	36	31	36	31	36	27	36	26	36	26	36	25
36	40	36	40	36	35	36	35	36	33	36	32	36	31	36	30	36	30	36	27	36	26

Table O-189. Summary of Results 2021 QV Analysis

Table O-189 shows the summary of results for the 2021 QV analysis.

To mitigate the reactive power shortfall, a 18.8 MVA synchronous condenser was added to Keahole and two synchronous condensers were added to Keaumuku (15.6 MVA and 18.8 MVA).

Con #	Contingency Description
36	L7700 Haina
50	L8600 Kahaluu

Table O-190. N-1 Contingencies 2021 QV Analysis

Table O-190 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

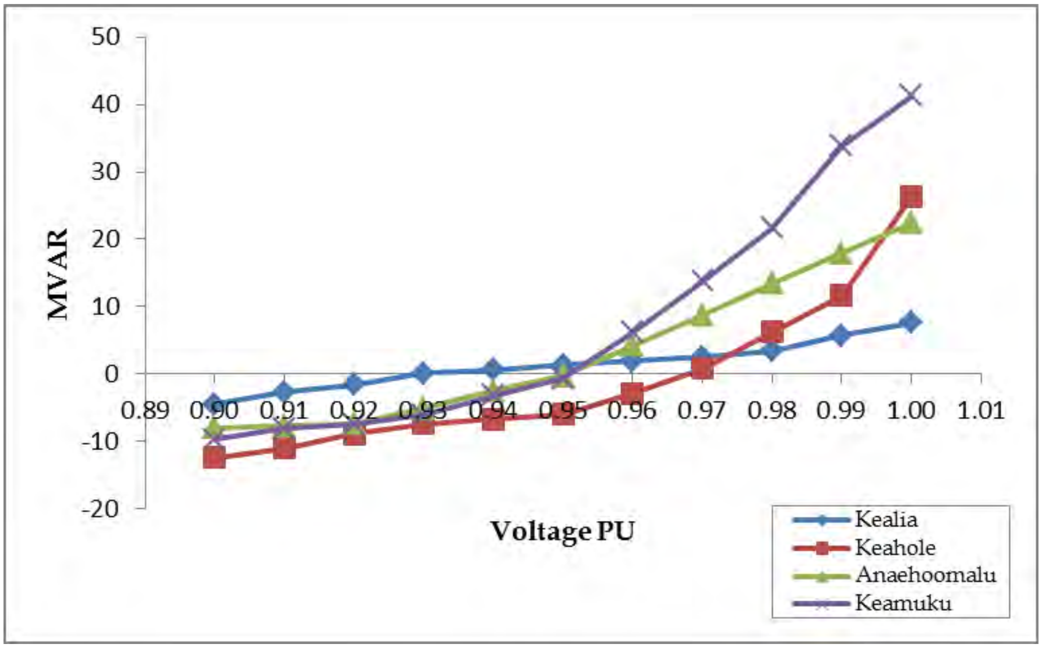

Figure O-405. QV Curves 2021

Figure O-405 shows the QV curves for the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses with the three synchronous condensers added to the system.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	8	36	6	36	3	50	3	50	2	50	1	50	1	50	0	50	-2	50	-3	50	-4
8400	Keahole	36	26	36	12	36	6	36	1	36	-3	36	-6	36	-7	36	-7	36	-9	36	-11	36	-12
8500	Anaehoomalu	36	22	36	18	36	13	36	9	36	4	36	0	36	-3	36	-5	36	-7	36	-8	36	-8
8700	Keamuku	36	41	36	34	36	22	36	14	36	6	36	-1	36	-3	36	-6	36	-7	36	-8	36	-10

Table O-191. Summary of Results 2021 QV Analysis Synchronous Condensers

Table O-191 shows the results of the QV analysis with the additional synchronous condensers. The Kealia bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Under this contingency, line L6200 is operating at 113% of its emergency rating which violates the transmission planning criteria. To mitigate the overload, the conductors for L6200 were increased from 336 AAC to 556 AAC to simulate a re-conductor project.

Con #	Contingency Description
36	L7700 Haina

Table O-192. N-1 Contingency 2021 QV Analysis

Table O-192 shows the N-1 contingency that has the greatest impact to MVAR requirements for the critical busses.

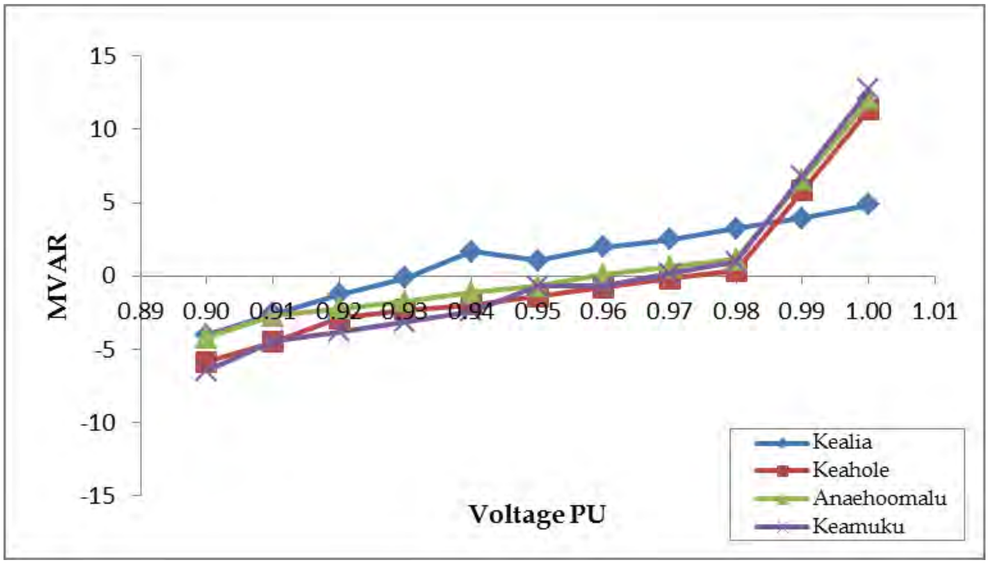

Figure O-406. QV Curves L6200 Reconductored

Figure O-406 shows the QV curves with the L6200 conductors increased from 336 AAC to 556 AAC.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	5	36	4	36	3	36	3	36	2	36	1	36	2	36	0	36	-1	36	-3	36	-4
8400	Keahole	36	11	36	6	36	0	36	0	36	-1	36	-1	36	-2	36	-2	36	-3	36	-4	36	-6
8500	Anaehoomalu	36	12	36	7	36	1	36	1	36	0	36	-1	36	-1	36	-2	36	-2	36	-3	36	-4
8700	Keamuku	36	13	36	7	36	1	36	0	36	-1	36	-1	36	-2	36	-3	36	-4	36	-4	36	-6

Table O-193. Summary of Results 2021 QV Analysis Synchronous Condensers

Table O-193 shows the results for the QV analysis with the L6200 conductors increased from 336 AAC to 556 AAC. The Kealia bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met. Increasing the ampacity of L6200 eliminates the overload condition and also meets the reactive power requirements of the system. No additional synchronous condensers are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

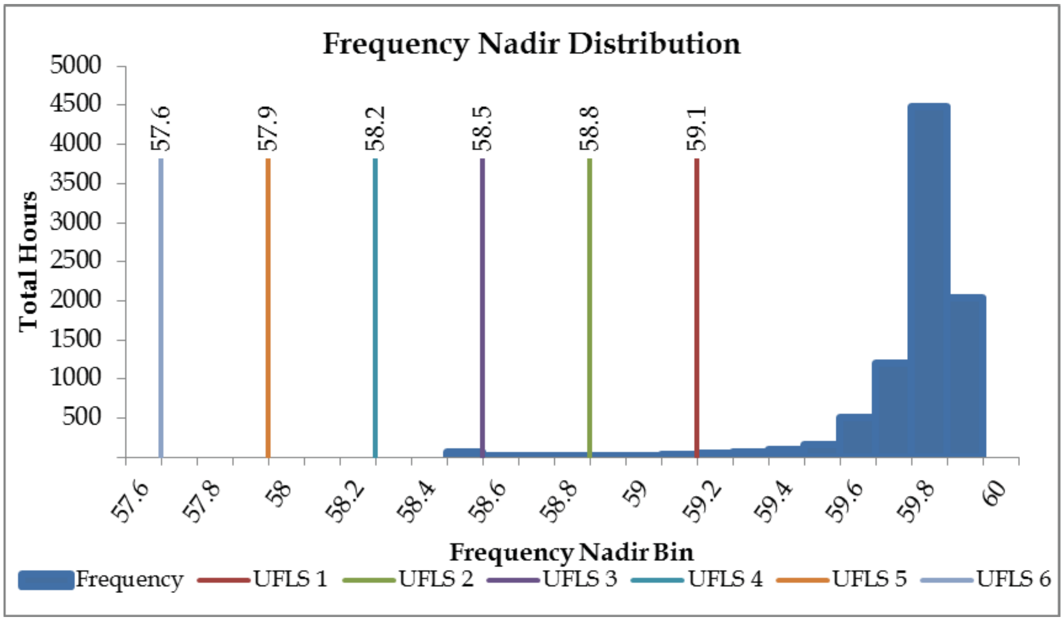

Figure O-407. Frequency Nadir Histogram 2020

Figure O-407 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 61 hours was 1:00 AM on Tuesday, January 19. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

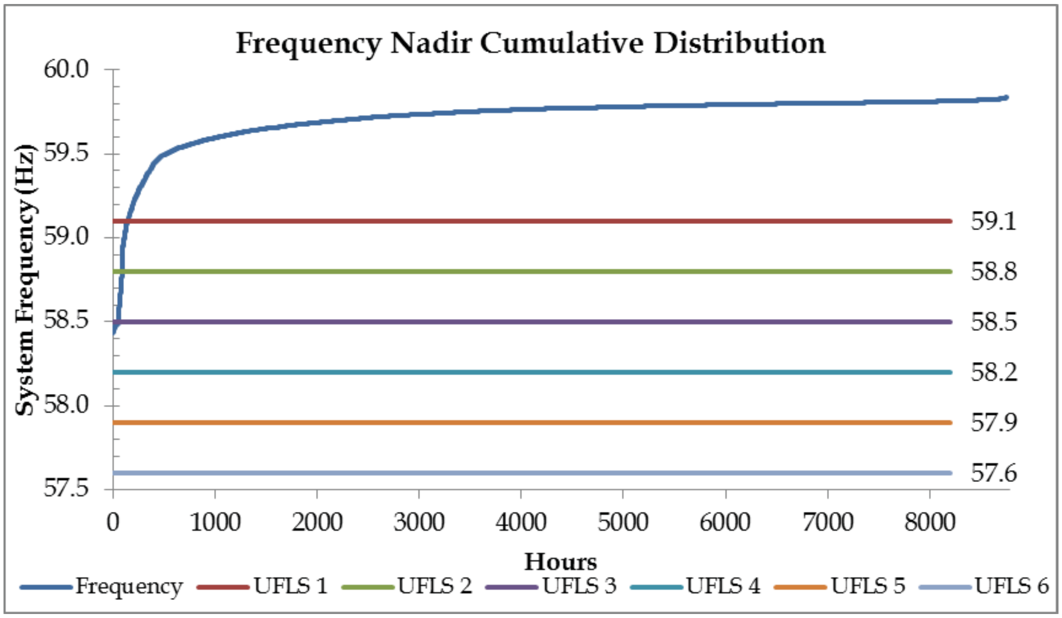

Figure O-408. Frequency Nadir Duration Curve 2021

Figure O-408 shows the frequency nadir duration curve for the Post April DR resource plan in 2021. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 61 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Tue 1/19/21 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	17.3	2.7	10.3
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	17.3	3.2	9.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.5		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	126.0	0						
Total Kinetic Energy						517		
Total Load						105		
Total Thermal Generation						101		
Total Renewable Generation						4		
Total Storage						0		
Total Generation						105		
Excess Generation						0		
Total Up Regulation						6		
Total Down Regulation						36		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-194. Unit Commitment and Dispatch 2021

Table O-194 shows the unit commitment and dispatch for the typical hour (1/19/21, 1:00 AM).

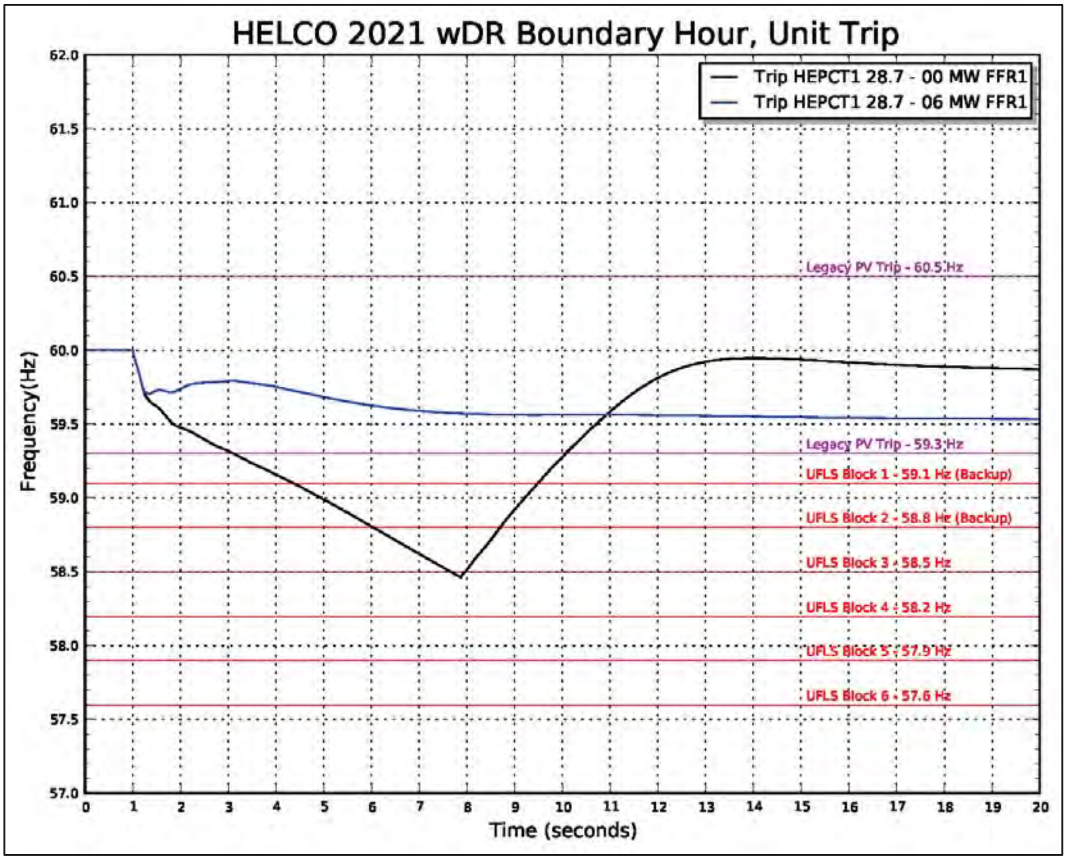

Figure O-409. Frequency Response Profile for FFR1 Boundary Hour

Figure O-409 shows the frequency response profile for a HEP CT1 trip at 28.7 MW. System kinetic energy is 517 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

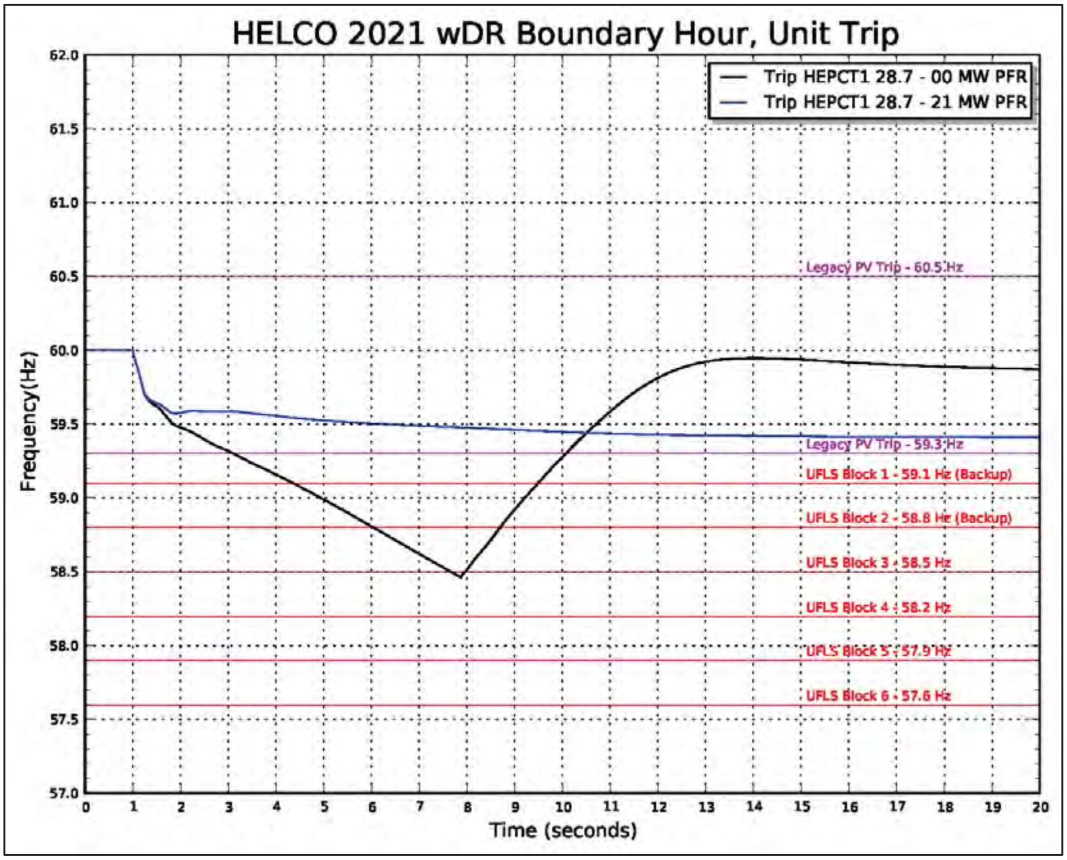

Figure O-410. Frequency Response Profile for PFR Boundary Hour

Figure O-410 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Sat 8/14/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199	18.9	35.1	11.9
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	5.0	8.5	0.0
Hill 6	20.5	8.0	2.53	27.5	70	8.0	12.5	0.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	9.6		
Apollo	20.5	0.0				19.6		
HRD	10.5	0.0				10.5		
Wind1	20.0	0.0				18.0		
Hydro	16.8	0				13		
Wind	91.0	0				48		
DG-PV	126.0	0				71		
Total Kinetic Energy						407		
Total Load						164		
Total Thermal Generation						32		
Total Renewable Generation						132		
Total Storage						0		
Total Generation						164		
Excess Generation						0		
Total Up Regulation						56		
Total Down Regulation						12		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.7
	60.5Hz Capacity			56.6		60.5Hz Output		33.2

Table O-195. Unit Commitment and Dispatch Fault Analysis

Table O-195 shows the unit commitment and dispatch for the 69 kV fault analysis (8/14/21, 1:00 PM).

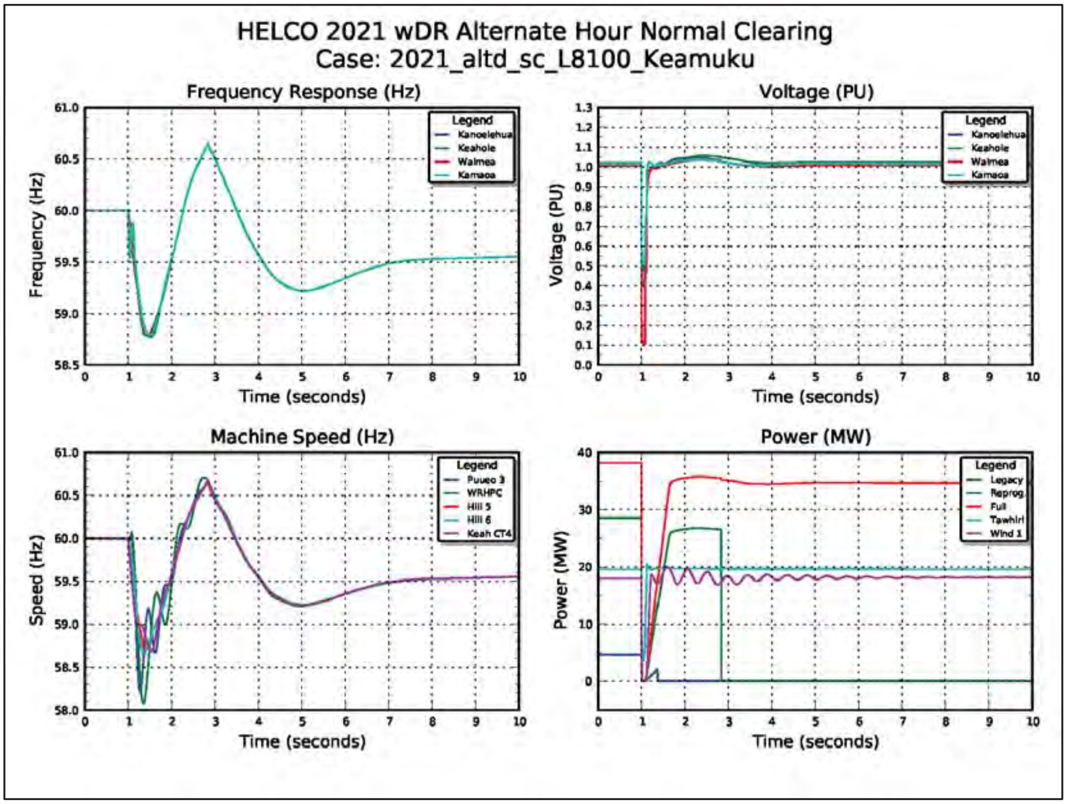

Figure O-411. System Performance Normally Cleared Fault

Figure O-411 shows the system performance for a normally cleared fault on the on the L8100 circuit near the Keamuku Substation. The frequency nadir is 58.7 Hz which is in compliance with TPL-001. Simulations of normally cleared faults were stable for all transmission circuits and in compliance with TPL-001. Improved system performance can be attributed to the commitment of Keahole in DTCC operation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

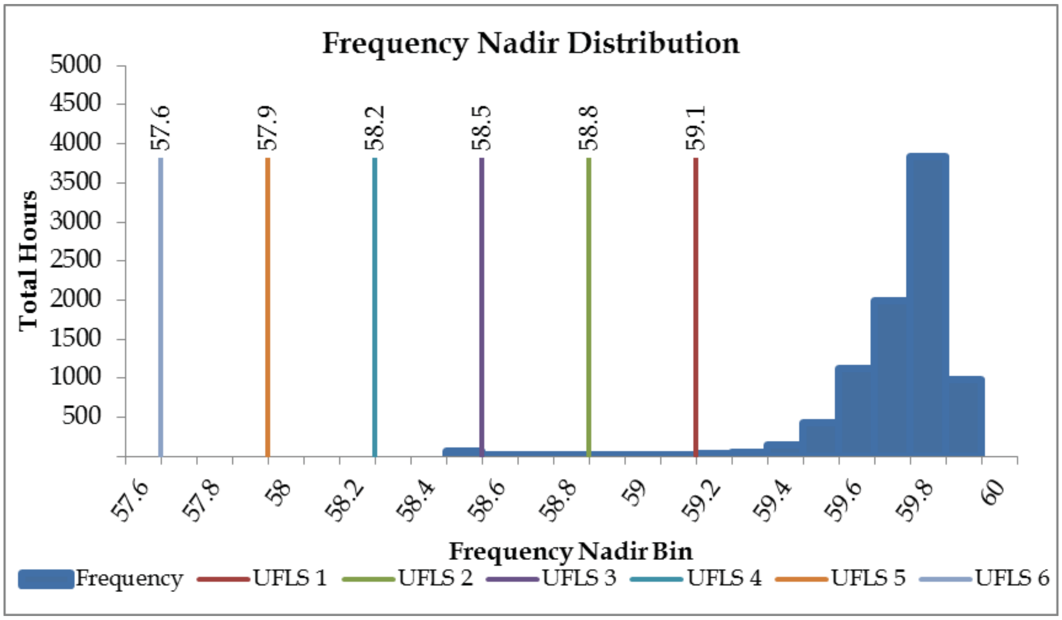

Figure O-412. Frequency Nadir Histogram 2025

Figure O-412 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 71 hours was 3:00 AM on Wednesday, February 26. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

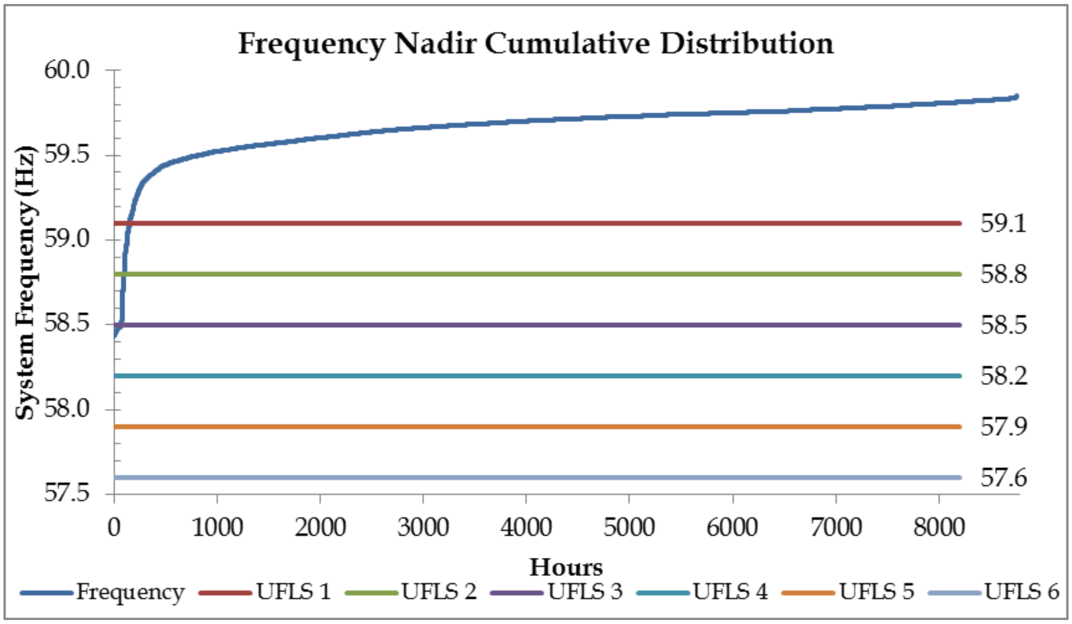

Figure O-413. Frequency Nadir Duration Curve 2025

Figure O-413 shows the frequency nadir duration curve for the Post April DR resource plan in 2025. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Wed 2/26/25 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.5	5.0	14.5
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.1		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				0		
DG-PV	136.4	0						
Total Kinetic Energy							594	
Total Load							95	
Total Thermal Generation							82	
Total Renewable Generation							14	
Total Storage							0	
Total Generation							95	
Excess Generation							0	
Total Up Regulation							5	
Total Down Regulation							31	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-196. Unit Commitment and Dispatch 2025

Table O-196 shows the unit commitment and dispatch for the typical hour (2/26/25, 3:00 AM).

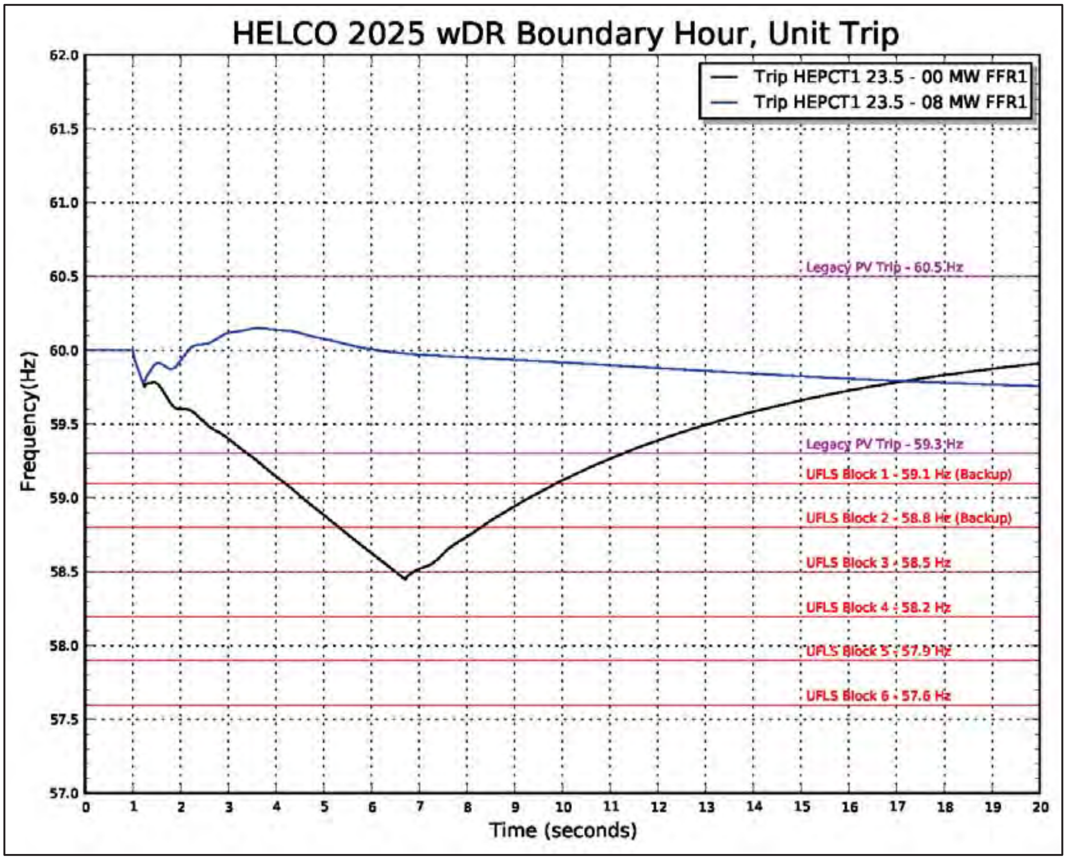

Figure O-414. Frequency Response Profile for FFR1 Boundary Hour

Figure O-414 shows the frequency response profile for a HEP CT1 trip at 23.5 MW. System kinetic energy is 594 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

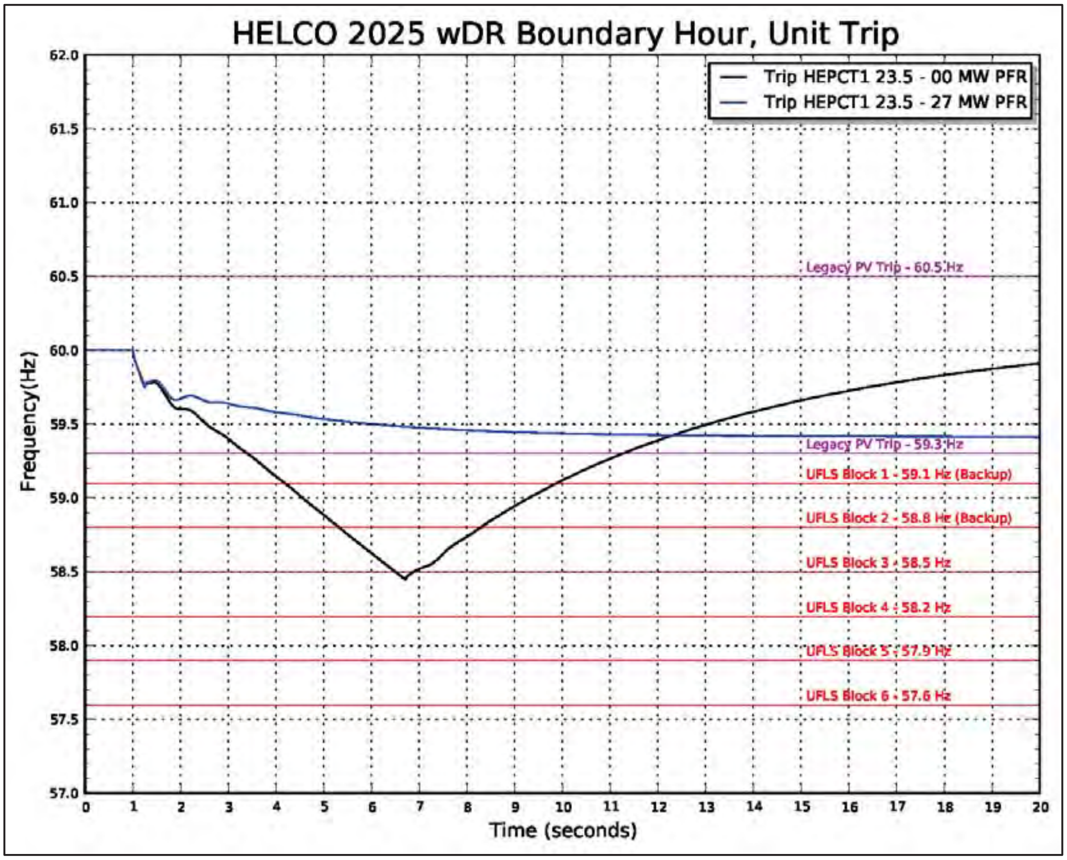

Figure O-415. Frequency Response Profile for PFR Boundary Hour

Figure O-415 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 27 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

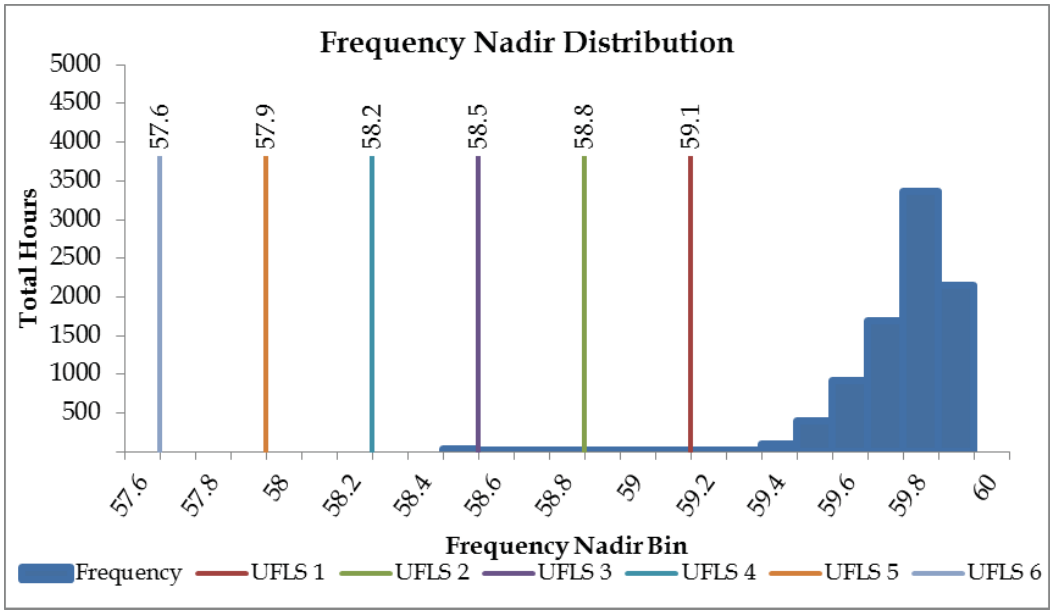

Figure O-416. Frequency Nadir Histogram 2030

Figure O-416 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 31 hours was 12:00 AM on Friday, January 25. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

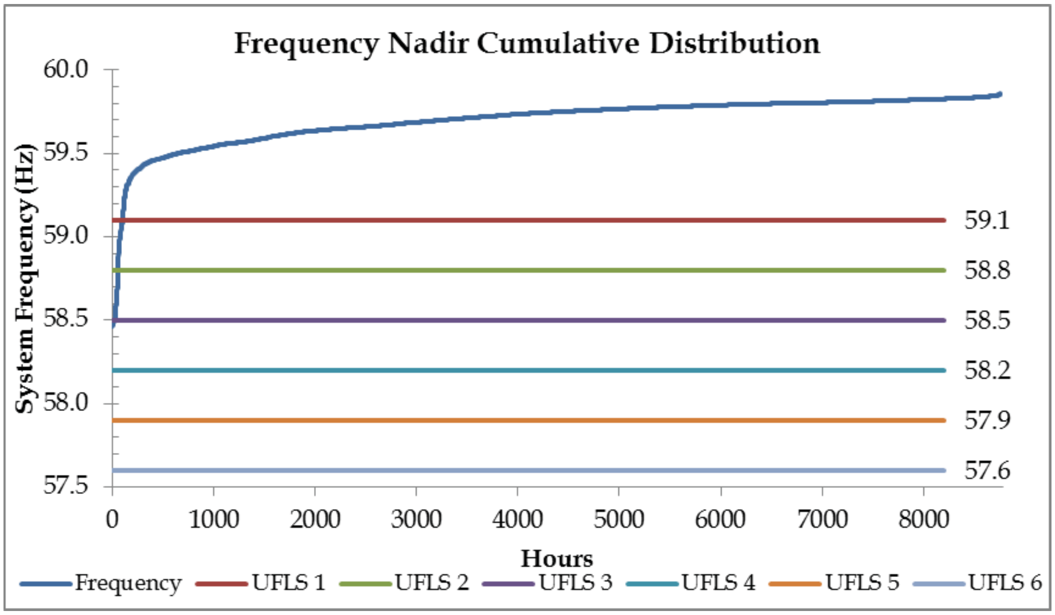

Figure O-417. Frequency Nadir Duration Curve 2030

Figure O-417 shows the frequency nadir duration curve for the Post April DR resource plan in 2030. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 31 hours of the year.

Unit Commitment Order	**Unit Ratings**					**DR - HEP STCC Trip Boundary Fri 1/25/30 Hour 24**		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.0	5.5	14.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Geo2	20.0		5.00	40.0	200	20.0	0.0	
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.9		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	148.3	0						
Total Kinetic Energy							794	
Total Load							105	
Total Thermal Generation							101	
Total Renewable Generation							4	
Total Storage							0	
Total Generation							105	
Excess Generation							0	
Total Up Regulation							5	
Total Down Regulation							30	
Legacy DG-PV	59.3Hz Capacity 60.5Hz Capacity			7.9 56.6		59.3Hz Output 60.5Hz Output		0.0 0.0

Table O-197. Unit Commitment and Dispatch 2030

Table O-197 shows the unit commitment and dispatch for the typical hour (1/25/30, 12:00 AM).

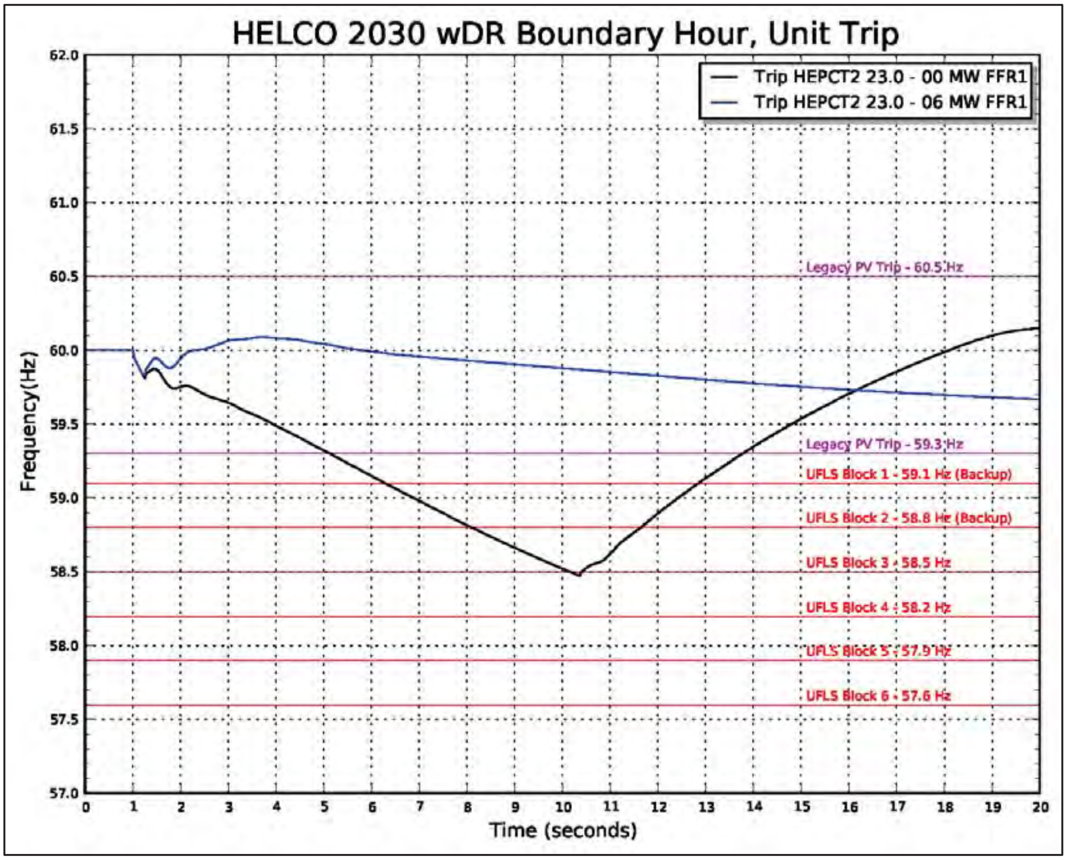

Figure O-418. Frequency Response Profile for FFR1 Boundary Hour

Figure O-418 shows the frequency response profile for a HEP CT2 trip at 23 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

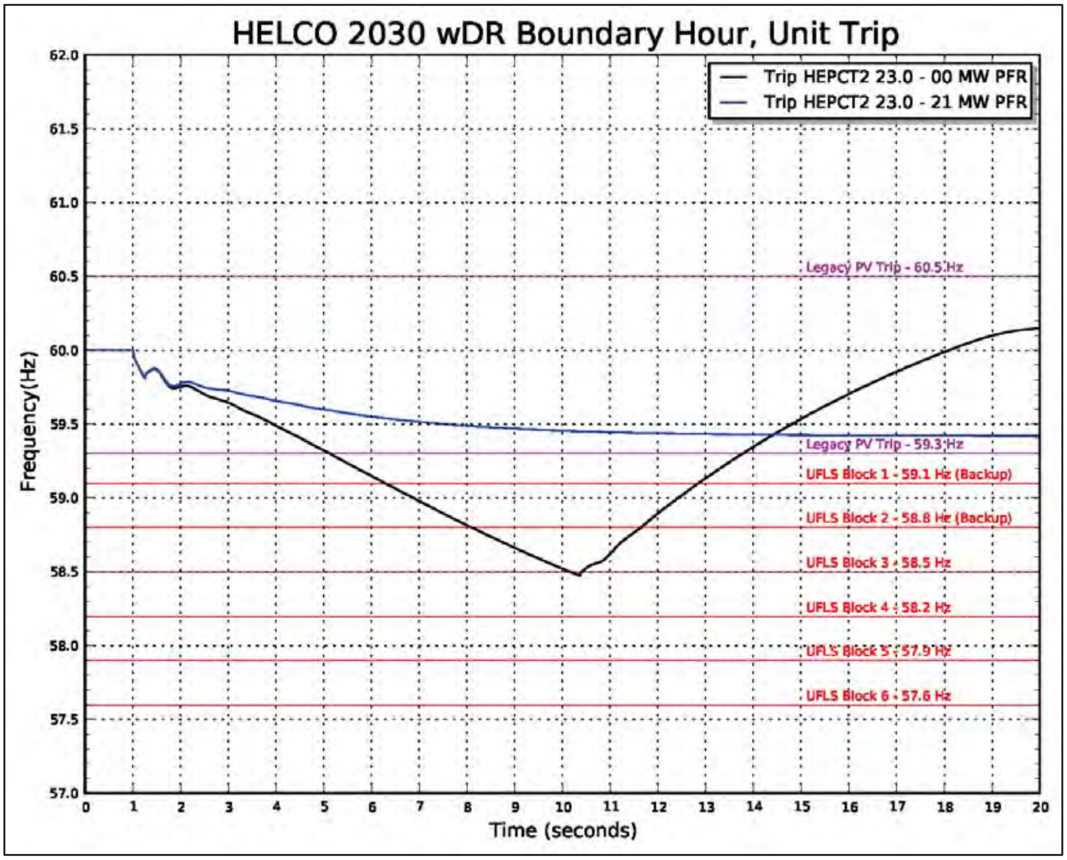

Figure O-419. Frequency Response Profile for PFR Boundary Hour

Figure O-419 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

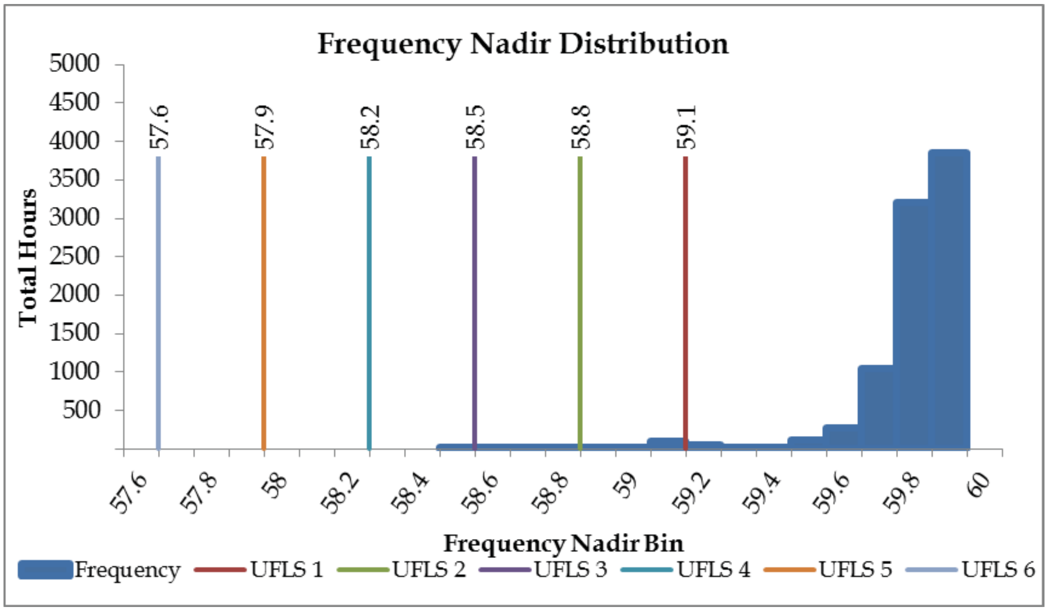

Figure O-420. Frequency Nadir Histogram 2045

Figure O-420 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 20 hours was 1:00 AM on Friday, January 27. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

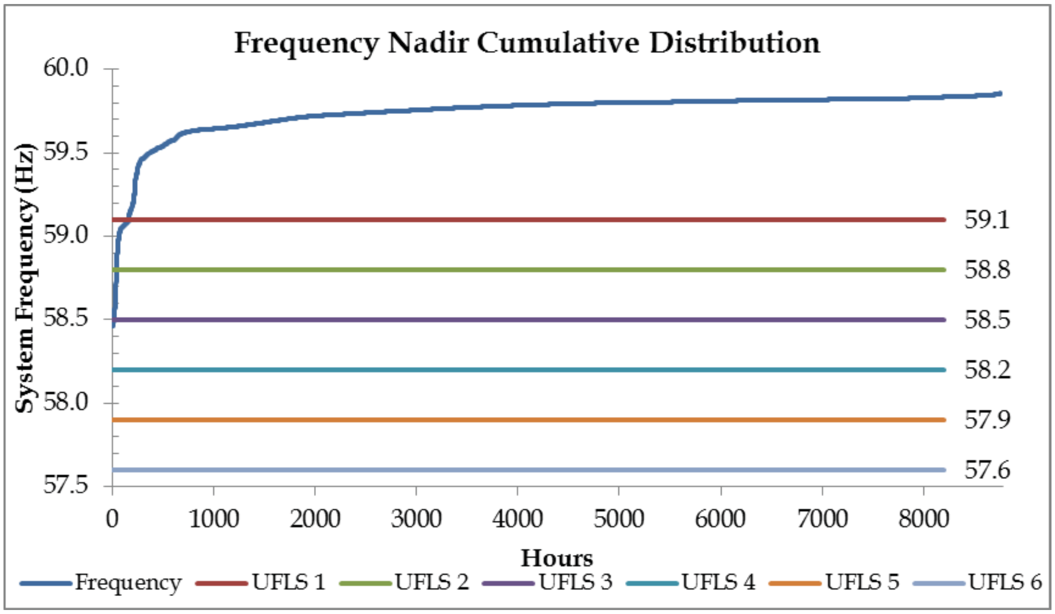

Figure O-421. Frequency Nadir Duration Curve 2045

Figure O-421 shows the frequency nadir duration curve for the Post April DR resource plan in 2045. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 20 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Fri 1/27/45 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.8	4.7	14.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Geo2	20.0		5.00	40.0	200	20.0	0.0	
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.8		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	191.0	0						
Total Kinetic Energy							794	
Total Load							106	
Total Thermal Generation							102	
Total Renewable Generation							4	
Total Storage							0	
Total Generation							106	
Excess Generation							0	
Total Up Regulation							5	
Total Down Regulation							31	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-198. Unit Commitment and Dispatch 2045

Table O-198 shows the unit commitment and dispatch for the typical hour (1/27/45, 1:00 AM).

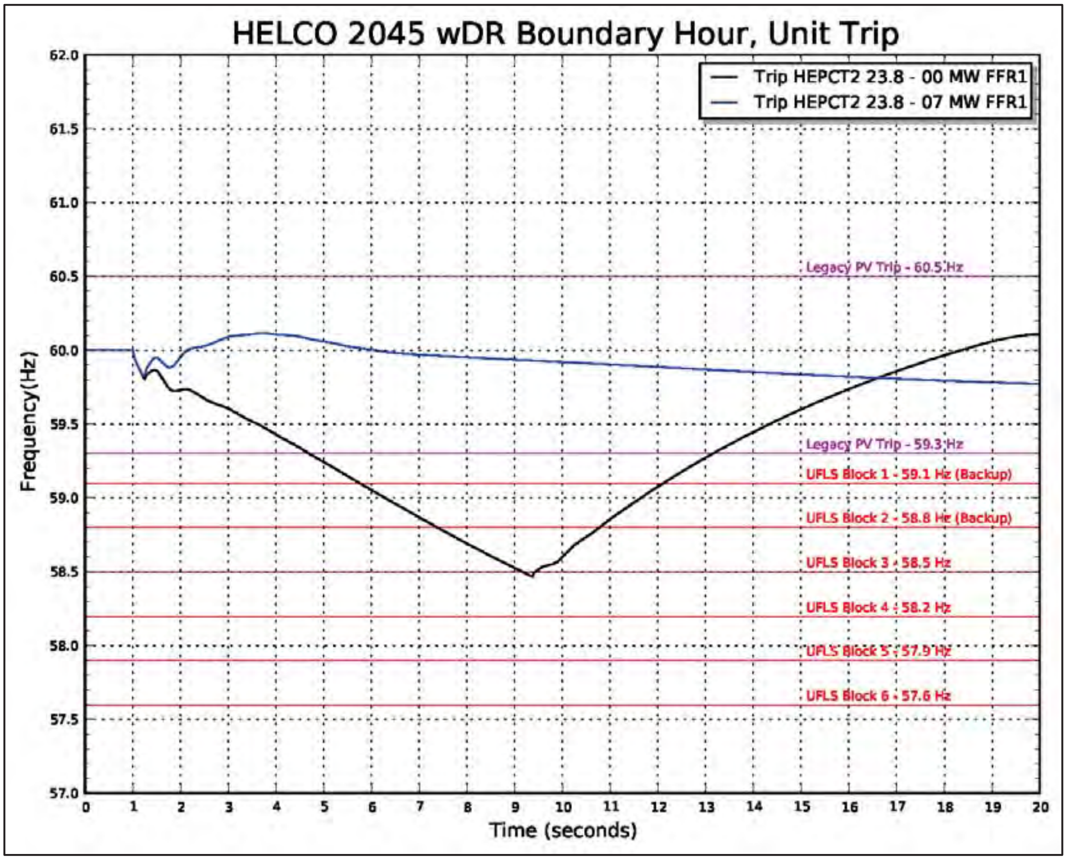

Figure O-422. Frequency Response Profile for FFR1 Boundary Hour

Figure O-422 shows the frequency response profile for a HEP STCC trip at 23.8 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

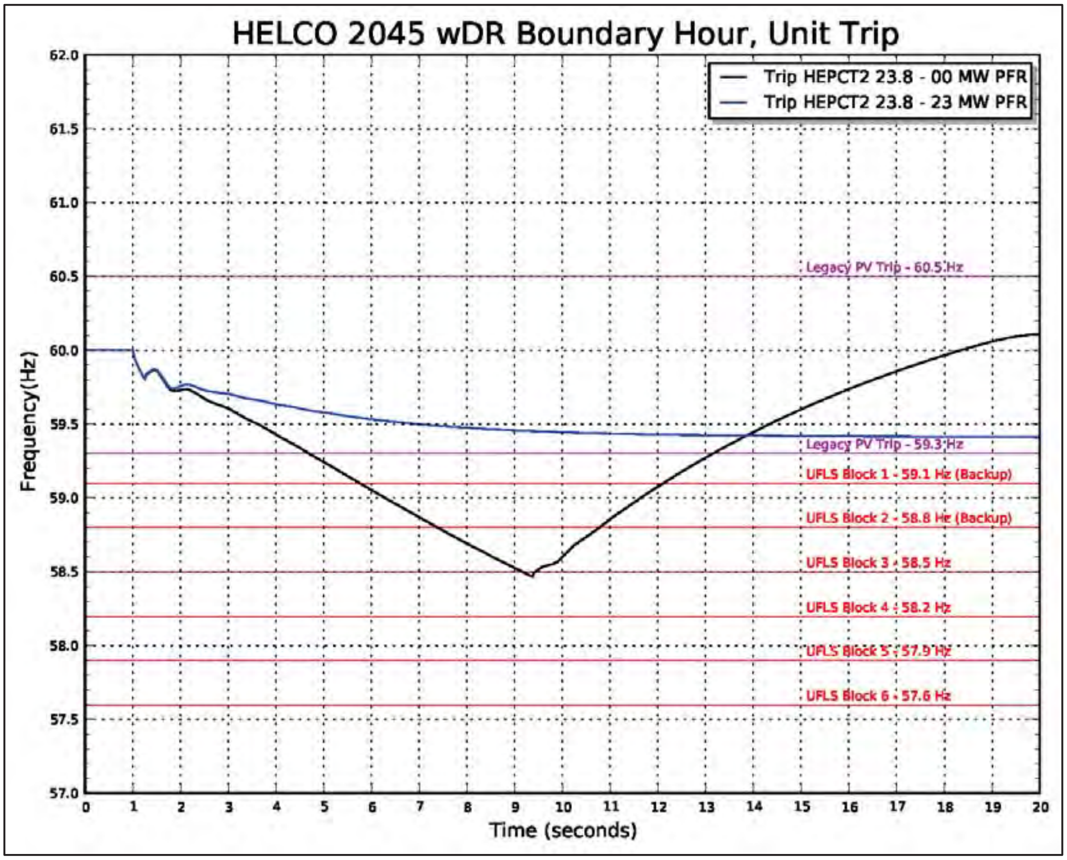

Figure O-423. Frequency Response Profile for PFR Boundary Hour

Figure O-423 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 23 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on the No LNG; High DG-PV plan.

E3 - No LNG; High DG-PV

- MVA Screening (2019 – 2030): Additional synchronous condensers required in 2022to meet the 80 MVA minimum fault current requirement.
- Loss of Generation Screening (2019 – 2030): Screening results indicate degraded system performance stating in 2020. The E3 plan has 485 hours that requires additional frequency response resource to meet TPL-001. The Post April DR plan had 71 hours. The hours at risk increase to 908 in 2025 and 3740 in 2030. This is attributed to a reduction in load to the point where the df/dt UFLS scheme is ineffective.

- 69 kV Fault Screening (2019 – 2022): All normally cleared faults were unstable in 2022 because of the different resource mix. The only synchronous units on the system are PGV and the hydro units.

Hawai‘i Island Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

Minimum Fault Current

A minimum fault current analysis was not performed for Hawai‘i. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Hawai‘i system requires 80 MVA of fault current capacity of which 25 MVA must be connected on the West side of the island. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

QV Analysis

The Hawai‘i transmission system is designed to operate with one transmission line out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability.

Only synchronous generators and synchronous condensers provide fault current to meet the minimum fault current requirements. Therefore, only synchronous condensers are evaluated in these analyses since resource plans tend to displace must-run units.

For Hawai‘i, the critical busses with the highest MVAR demand are the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

A new 25 MVA synchronous condenser is required in 2020 for both the Theme 3 No-DR and the Post April DR plans.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

For the Theme 3 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. The capacity of FFR1 required to bring the system into compliance with TPL-001 in 2019 is 6 MW for a typical hour. Table O-207 (page O-618) shows the results of the analysis.

For the Post April DR resource plan, analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Hawai‘i does not have capacities of FFR2 in their Demand Response portfolio. The capacity of FFR1 required to bring the system into compliance with TPL-001 in 2019 is 9 MW for a boundary hour. Table O-208 (page O-618) shows the results of the analysis.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Simulations were performed to determine the capacity of PFR required to bring the system into compliance with TPL-001 and to evaluate 5-cycle clearing time to simulate performance of dual pilot or dual differential relay schemes. Table O-199 shows the results of the PFR analysis to bring the Hawai‘i system into compliance with TPL-001.

Year	PFR (MW)	
	No DR	DR
2019	19	10
2020	18	16
2021	17	None

Table O-199. Summary of Results PFR Analysis

The 2021 Post April DR plan meets the requirements of TPL-001 because Keahole DTCC is running. Further analysis is required to determine optimal mitigating strategies to maintain system security.

TPL-001 TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-2 was HI-TPL-001. The standard was revised to reflect the distinct electrical systems for O‘ahu, Maui, and Hawai‘i Island. Lana‘i and Moloka‘i were removed from HI-TPL-001-02 because they are 12 kV distribution systems.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions become approved when this proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Base Year: The 2011 Balancing Authority’s transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Term Approved August 4, 2011.)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Table O-200.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady-state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Frequency Bias: A value expressed in MW/0.1 Hz that is set into the Automatic Generation Control's (AGC) Area Control Error (ACE) algorithm that allows the Balancing Authority to control system frequency.

Frequency Response: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hz (MW/0.1 Hz)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the positions identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection Systems are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System or Under Voltage Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAR), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include under-frequency or under-voltage load shedding or out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission Line: A system of structures, wires, insulators, and associated hardware that carry electrical energy form one point to another in an electric power system. Lines are operated at relatively high voltages varying from nominal 69 kV up to 138 kV.

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The facilities are divided into three island systems.

O‘ahu: 2015 Data

- Daytime peak load: 1,110 MW
- Daytime minimum load: 551 MW
- Nighttime peak load: 1,204 MW
- Nighttime minimum load: 506 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 482.6 MVA

Maui: 2015 Data

- Daytime peak load: 180.9 MW
- Daytime minimum load: 88.6 MW
- Nighttime peak load: 206.6 MW
- Nighttime minimum load: 74.5 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 101.3 MVA

Hawai‘i Island: 2015 Data

- Daytime peak load: 173.1 MW
- Daytime minimum load: not applicable
- Nighttime peak load: 191.5 MW
- Nighttime minimum load: 82.6 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 140 MVA

Effective Date: April 1, 2016

Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table O-200.

R1.1. System models must represent:

  R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations.

  R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

  R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

  R1.2.1. Each BA system will be planned to meet the requirements of Table O-200.

  R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable performance criteria defined in Table O-200.

  R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table O-200.

  R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response, or reserve response will withstand contingency events defined in Table O-200.

  R1.2.5. The system will be planned such that all generation, reserves, regulation, and voltage control resources will withstand the most severe voltage ride-through requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table O-200.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 under-frequency load shedding. Stability will be defined such that the system will survive the first swing stability and the second swing, and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within five seconds of the initiating event.

R1.2.8. The system will be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and Table O-200.

R2. The BA must prepare a Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady-state analyses, short circuit analyses, and stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, one or more sensitivity cases must demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services.
- Typical generation scenarios including outage of the typically operated generation sources.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table O-200 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6.

- Minimum short circuit current for proper relay operation: The minimum short circuit current for each BA is specified in the Introduction.
- Maximum short circuit current interrupting capabilities of the breakers must be within the limits for proper breaker operation. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response, and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, one or more sensitivity cases must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements for steady-state, short circuit, or Stability analysis:

R2.6.1. The study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table O-200 when the analysis indicates an inability of the system to meet the performance requirements, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned system must continue to meet the performance requirements in Table O-200. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady-state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives.

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table O-200, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve the required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady-state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1 and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table O-200 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 and R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Include in the assessment any assumptions made.
- Tripping of transmission elements where loadability limits are exceeded.

- Tripping of generation and other resources (including distributed resources) where ride-through capabilities are exceeded.

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady-state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table O-200 that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table O-200 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the planning assessment (as described in R2.4 and R2.5), the BA must perform the contingency analyses listed in Table O-200. The studies must be based on computer simulation models using data provided in R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table O-200 based on the Contingency list created in R4.4. For planning events P1 through P4:

R4.1.1. No generating unit can pull out of synchronism.

R4.1.2. Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-through capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators, and power flow controllers.

R4.4. Those planning events in Table O-200 that are expected to produce more severe system impacts on its portion of the system must be identified and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table O-200 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA shall have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, transient voltage response, transmission facilities overloading criteria, and dynamic stability criteria (voltage and frequency). For transient voltage response, the criteria shall at the minimum specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA shall define and document, within their Planning Assessment, the criteria or the methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding.

Planning Events

Planning Event	Initial Condition	Event	Non-Consequential Load Shed			UFLS or UVLS		
			O‘ahu	Maui	Hawai‘i Island	O‘ahu	Maui	Hawai‘i Island
P0: No Contingency	Normal system N-1 Maintenance N-2 Maintenance	None	n/a	n/a	n/a	None	None	None
P1.1: Loss of One Generating Unit	Normal system	Unit Trip Bus Fault	None	None	None	None	15%	15%
P.1.2: Loss of One Transmission Element	Normal system	SLG, 2Ø, 3Ø, Breaker Fail	None	None	None	None	None	None
P2.1: Loss of Two Generating Units	Normal system	Unit Trip Bus Fault	tbd	tbd	tbd	tbd	tbd	tbd
P2.2: Loss of Two Transmission Elements	N-1	SLG, 2Ø, 3Ø, Breaker Fail	None	tbd	tbd	None	tbd	tbd
P3.1: Loss of Multiple Generating Units	Normal system	Loss of Combined Cycle unit	tbd	tbd	tbd	tbd	tbd	tbd
P3.2: Loss of Multiple Transmission Elements	N-2	SLG, 2Ø, 3Ø, Breaker Fail	tbd	tbd	tbd	tbd	tbd	tbd
P4: Catastrophic Event	Normal system	Loss of Generating Station Loss of Transmission Corridor	tbd	tbd	tbd	tbd	tbd	tbd

Table O-200. Transmission Performance Requirements

Measures

M1. The BA must provide evidence, in hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence (such as electronic or hard copies) that it has prepared an annual Planning Assessment of its portion of the system in accordance with R2.

M3. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R3.

M4. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R4.

M5. The BA must provide dated evidence (such as electronic or hard copies) of the documentation specifying the criteria for acceptable system steady-state voltage limits, post contingency voltage deviations, and transient voltage utilized in preparing the Planning Assessment in accordance with R5.

M6. The BA must provide dated evidence (such as electronic or hard copies) of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with R6.

Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority: Hawai‘i Public Utilities Commission or its designee.

C1.2. Data Retention: The BA must retain data or evidence to show compliance as identified unless directed by the Commission (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with R1 and M1.
- The Planning Assessments performed since the last compliance audit in accordance with R2 and M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R3 and M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R4 and M4.
- The documentation specifying the criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with R5 and M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions (such as cascading, voltage instability or uncontrolled islanding) in support of its Planning Assessments since the last compliance audit in accordance with R6 and M6.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

C1.3. Compliance monitoring and enforcement processes:

- Compliance Audits: The Commission (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-certifications
- Spot checking
- Compliance violation investigations
- Self-reporting
- Complaints

C2. Levels of non-compliance for R1 and M1:

C2.1. Level 1: The BA's system model failed to represent one of the requirement in R1.1.1 through R1.1.5.

C2.2. Level 2: The BA failed to meet all the requirements of C2.1 Level 1.

C3. Levels of non-compliance for R2 and M2:

C3.1. Level 1: The BA failed to comply with R2.6.

C3.2. Level 2: The BA failed to meet all the requirements of C3.1 Level 1.

C4. Levels of non-compliance for R3 and M3:

C4.1. Level 1: The BA did not identify planning events as described in R3.4 or extreme events as described in R3.5.

C4.2. Level 2: The BA failed to meet all the requirements of C4.1 Level 1.

C5. Levels of non-compliance for R4 and M4:

C5.1. Level 1: The BA did not identify planning events as described in R4.4 or extreme events as described in R4.5.

C5.2. Level 2: The BA failed to meet all the requirements of C5.1 Level 1.

C6. Levels of non-compliance for R5 and M5:

C6.1. Level 1: not applicable.

C6.2. Level 2: The BA does not have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, or the transient voltage response for its system for R5 and M5.

C7. Levels of non-compliance for R6 and M6:

C7.1. Level 1: not applicable.

C7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in R6 and M6.

FREQUENCY RESPONSE ANALYSIS RESULTS

O‘ahu Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2022			2023			2025			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical	AES 189	4518	120	AES 189	4161	120	AES 189	3735	130	AES 189	3378	140	K5 135	3546	100	GE CT 151	3446	120	GE CT 151	2777	120	OSW 165	1002	140
	Boundary	AES 189	3735	140	AES 189	3378	140	AES 189	3378	140	AES 189	2686	150	K5 128	1651	100	GE CT 151	3410	120	GE CT 151	3435	130	OSW 165	1002	150
FFR2	Typical	AES 189	4518	130	AES 189	4161	130	AES 189	3735	140	AES 189	3378	150	K5 135	3546	100	GE CT 151	3446	120	GE CT 151	2777	120	OSW 165	1002	N/A
	Boundary	AES 189	3735	150	AES 189	3378	150	AES 189	3378	150	AES 189	2686	170	K5 128	1651	130	GE CT 151	3410	120	GE CT 151	3435	130	OSW 165	1002	N/A
PFR	Typical	AES 189	4518	310	AES 189	4161	320	AES 189	3735	350	AES 189	3378	350	K5 135	3546	210	GE CT 151	3446	260	GE CT 151	2777	260	OSW 165	1002	510
	Boundary	AES 189	3735	370	AES 189	3378	370	AES 189	3378	370	AES 189	2686	420	K5 128	1651	360	GE CT 151	3410	240	GE CT 151	3435	250	OSW 165	1002	540
FFR1 (K5 Trip)	Typical	K5 135	4092	90	K5 135	4161	80	K5 135	3735	90	K5 135	3378	100												
	Boundary	K5 135	3735	100	K5 135	3378	110	K5 135	3378	100	K5 135	2787	110												
FFR2 (K5 Trip)	Typical	K5 135	4092	90	K5 135	4161	80	K5 135	3735	90	K5 135	3378	100												
	Boundary	K5 135	3735	100	K5 135	3378	110	K5 135	3378	110	K5 135	2787	110												
PFR (K5 Trip)	Typical	K5 135	4092	210	K5 135	4161	210	K5 135	3735	230	K5 135	3378	230												
	Boundary	K5 135	3735	260	K5 135	3378	250	K5 135	3378	260	K5 135	2787	290												

Table O-201. Summary of Result Frequency Response Analysis – Theme 5 No DR: O‘ahu

Freq Response Reserves	Case	2019				2020				2021				2022				2023				2025				2030				2045			
		Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)
FFR1	Typical	AES 189	4098	47.4	70	AES 189	3838	48.8	70	AES 189	4087	46.8	70	AES 189	3869	38	90	K5 135	4780	49.1	20	GE 151	4058	41	40	GE 151	4276	32.5	60	OSW 159	1146	48	70
	Boundary	AES 189	3502	25.6	110	AES 189	3433	34.8	100	AES 189	3586	32.2	100	AES 189	3416	32.8	100	K5 135	3564	35.1	50	GE 151	3467	31.9	70	GE 150	3555	32.7	90	OSW 145	1002	40	90
PFR	Typical	AES 189	4098	47.4	200	AES 189	3838	48.8	200	AES 189	4087	46.8	190	AES 189	3869	38	200	K5 135	4780	49.1	50	GE 151	4058	41	90	GE 151	4276	32.5	120	OSW 159	1146	48	200
	Boundary	AES 189	3502	25.6	290	AES 189	3433	34.8	260	AES 189	3586	32.2	260	AES 189	3416	32.8	260	K5 135	3564	35.1	110	GE 151	3467	31.9	130	GE 150	3555	32.7	180	OSW 145	1002	40	320
FFR1 (K5 Trip)	Typical	K5 135	4104	47.4	30	K5 135	3678	48.8	40	K5 135	3996	46.8	40	K5 135	3847	38	60																
	Boundary	K5 135	3411	25.6	70	K5 135	3411	34.8	60	K5 135	3591	32.2	60	K5 135	3660	32.8	60																
PFR (K5 Trip)	Typical	K5 135	4104	47.4	100	K5 135	3678	48.8	100	K5 135	3996	46.8	100	K5 135	3847	38	120																
	Boundary	K5 135	3411	25.6	160	K5 135	3411	34.8	130	K5 135	3591	32.2	140	K5 135	3660	32.8	130																

Table O-202. Summary of Results Frequency Response Analysis – Post April DR: O‘ahu

Maui Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2023			2030			2045		
		Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)
FFR1	Typical	KWP I 29	300	9	KWP I 27	305	8	KWP I 27	437	8	WIND I 30	295	12						
	Boundary	KWP I 30	300	10	WIND I 30	316	9	KWP I 29.7	597	12	KWP I 30	295	11	KWP I 30	469	4	KWP I 30	638	0
FFR2	Typical	KWP I 29	300	11	KWP I 27	305	10	KWP I 27	437	9	WIND I 30	295	14						
	Boundary	KWP I 30	300	13	WIND I 30	316	11	KWP I 29.7	597	15	KWP I 30	295	13	KWP I 30	469	5	KWP I 30	638	0
PFR	Typical	KWP I 29	300	16	KWP I 27	305	15	KWP I 27	437	14	WIND I 30	295	21						
	Boundary	KWP I 30	300	19	WIND I 30	316	17	KWP I 29.7	597	21	KWP I 30	295	20	KWP I 30	469	8	KWP I 30	638	0

Table O-203. Summary of Results Frequency Response Analysis - Theme 3 No DR: Maui

Freq Response Reserves	Case	2019			2020			2021			2022			2023			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical	KWP I 29.7	299	8	KWP I 29.1	292	8	KWP I 29.5	292	9	KWP I 29.9	273	14	KWP I 29.2	316	7	KWP I 29.4	403	7			
	Boundary	KWP I 29.6	270	9	KWP I 29.8	292	8	KWP I 29.8	292	8	KWP I 30	273	10	KWP I 29.2	229	14	KWP I 29.2	403	8	LS BESS 30	403	2
PFR	Typical	KWP I 29.7	299	16	KWP I 29.1	292	15	KWP I 29.5	292	15	KWPI 29.9	273	23	KWP I 29.2	316	13	KWP I 29.4	403	13			
	Boundary	KWP I 29.6	270	15	KWP I 29.8	292	14	KWP I 29.8	292	14	KWP I 30	273	14	KWP I 29.2	229	22	KWP I 29.2	403	14	LS BESS 30	403	3

Table O-204. Summary of Frequency Response Analysis Post April DR: Maui

Lana‘i Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
	Boundary	L7 1.2MW	9	1.25	L8 2.2MW	9	2.4	L8 2.17MW	9	2.4	L8 2.2MW	9	2.4	L8 2.2MW	9	0
PFR	Typical	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
	Boundary	L7 1.2MW	9	1.25	L8 2.2MW	9	2.4	L8 2.17MW	9	2.4	L8 2.2MW	9	2.4	L8 2.2MW	9	0

Table O-205. Summary of Results Frequency Response Analysis: Lana'i

Moloka‘i Frequency Response Results

Freq Reponse Reserves	Case	2019			2020			2030			2045		
		Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)
FFR1	Typical	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
	Boundary	D9 2.2MW	6	2.75	D9 2.1MW	6	2.5	D9 2.2MW	6	2.5	D9 2.1MW	6	2.15
PFR	Typical	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
	Boundary	D9 2.2MW	6	3.25	D9 2.1MW	6	3.25	D9 2.2MW	6	3.25	D9 2.1MW	6	3.25

Table O-206. Summary of Results Frequency Response Analysis: Moloka'i

Hawai‘i Island Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2025			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical				HEP 22.0	373.5	6	HEP 25.9	373.5	7									
	Boundary	KEAH 23.9	423.6	5	HEP 24.0	373.5	11	HEP 24.7	373.5	8	HEP 23.8	573.5	7	HEP 26.4	773.5	5	HEP 25.7	662	5
FFR2	Typical				HEP 22.0	373.5	6	HEP 25.9	373.5	7									
	Boundary	KEAH 23.9	423.6	5	HEP 24.0	373.5	11	HEP 24.7	373.5	8	HEP 23.8	573.5	7	HEP 26.4	773.5	5	HEP 25.7	662	5
PFR	Typical				HEP 22.0	373.5	19	HEP 25.9	373.5	23									
	Boundary	KEAH 23.9	423.6	18	HEP 24.0	373.5	36	HEP 24.7	373.5	29	HEP 23.8	573.5	24	HEP 26.4	773.5	15	HEP 25.7	662	16

Table O-207. Summary of Results Frequency Response Analysis – Theme 3 No DR: Hawai‘i Island

Freq Response Reserves	Case	2019				2020				2021				2025				2030				2045			
		Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)
FFR1	Typical																								
	Boundary	HEP 28.7	448.6	N/A	8	HEP 28.7	397.8	N/A	9	HEP 28.7	448.4	N/A	6	HEP 23.5	525.8	N/A	8	HEP 23.0	725.8	N/A	6	HEP 23.8	725.8	N/A	7
PFR	Typical																								
	Boundary	HEP 28.7	448.6	N/A	26	HEP 28.7	397.8	N/A	31	HEP 28.7	448.4	N/A	21	HEP 23.5	525.8	N/A	27	HEP 23.0	725.8	N/A	21	HEP 23.8	725.8	N/A	23

Table O-208. Summary of Results Frequency Response Analysis – Post April DR: Hawai‘i Island

P. Consultant Reports

Three consultants worked in concert with the Companies to participate in the modeling and analyses required to develop the December 2016 updated PSIP:

Energy and Environmental Economics (E3) ran their RESOLVE model to develop theoretical least-cost plans; Ascend Analytics ran their PowerSimm Planner model essentially to validate the E3 plans; and Black and Veatch ran their Adaptive Planning for Production Simulation model to evaluate Demand Response for the PSIP action plans.

Each wrote a report of their work. Those reports are included here as submitted, and accepted.

E3 December 2016 PSIP Update

Summary of findings from RESOLVE modeling of Oahu, Maui, and Hawai'i Islands

December 23, 2016

Energy+Environmental Economics

E3 December 2016 PSIP Update

Summary of findings from RESOLVE modeling of Oahu, Maui, and Hawai'i Islands

December 23, 2016

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1: INTRODUCTION

Q1. WHAT WAS ENERGY AND ENVIRONMENTAL ECONOMICS INC (E3) SCOPE OF WORK?

A1. The Companies initially hired E3 in June of 2016 to use its RESOLVE model to look at the potential net benefits provided by interconnecting the island systems via undersea transmission cables. This scope was expanded in August of 2016 to include a range of sensitivities provided by the Companies and stakeholders. E3 used this same model in the previous PSIP filing in April of 2016 and have described the model, results and input assumptions in two different workshops.

E3's deliverables for this round of the PSIP include least cost resource plans for Oahu, Maui and Hawaii as independent, non-interconnected island systems, as well as for grid-interconnected systems, using reference assumptions developed through several weeks of consultations with the Company team. The model results serve a specific purpose in the PSIP – to produce an initial set of least cost recommendations for the 5-year plans that will be both validated and refined by the Companies using both practical interconnection and transmission limitations, feasible block sizes for generation additions and more detailed operational models that look more closely at reliability.

A second set of deliverables includes sensitivity analysis around the reference cases to investigate the impact of different assumptions about how the future will unfold on the decisions made in the 5-year plan. These sensitivities have been determined by the Companies working closely with stakeholders throughout the process.

Q2. WHAT IS THE KEY DIFFERENCE BETWEEN THE ROLE YOU PLAYED IN THE PREVIOUS PSIP FILING AND YOUR WORK HERE?

A2. Our earlier results were produced by the E3 team working independently of the process used by the Companies using a mixture of input assumptions from the company work and our own database looking only at Oahu. In this revision, we have expanded the analysis to include Maui and Hawaii and all input assumptions have been provided by the Company team and revised through close collaboration with them and input from stakeholders, over the last 5 months. We show results of cases defined by the companies and those defined by stakeholders separately. We have also extended our analysis beyond studies of the islands individually to provide a rough upper bound bookend of the value of interconnecting the islands with undersea transmission cables as a first screen to test whether a more detailed intertie study is warranted.

Q3. WHAT WAS THE PROCESS YOU USED TO DEVELOP YOUR FINDINGS IN THIS UPDATED PSIP FILING?

A3. The process was developed based on feedback from stakeholders regarding the lack of transparency in the previous PSIP filing. To increase both the transparency of results and allow third parties to participate more effectively in the process, the methodology, the cases being run, and the inputs assumptions were discussed over two workshops at the HPUC with stakeholders and commission staff. The role of the E3 analysis as a precursor to more detailed modeling being conducted by the Companies was also presented. The input data assumptions are presented in detail for each island in the Appendix to this report.

Our role in this process was not to choose the best plan, but to provide an independent and unbiased assessment of the least cost incremental system capacity investments and dispatch decisions for each island necessary to meet Hawaii's RPS goals under the assumptions defined for the reference and sensitivity cases and make those results and cases equally transparent and accessible to all parties.

Costs were examined from a Total Resource Cost perspective meaning that customer costs for customer-sited generation were considered in the optimizations in both the core and sensitivity cases that allow optimal DGPV resource selection.

Q4. PLEASE BRIEFLY DESCRIBE THE CASES YOU DEVELOPED FOR THE COMPANIES AND STAKEHOLDERS.

A4. Each case was focused on varying certain input parameters to investigate various uncertainties. The key variations in the input parameters for each case are summarized here with further details describing each case listed below.

For each island, we investigate the sensitivity of the least cost resource plan to two major uncertainties for the Companies – the scale of DGPV buildout and the option to invest in LNG resources beginning in 2022. To test both sensitivities, we used the Companies-produced "Market" DGPV forecast and the "High" DGPV forecast as inputs into the RESOLVE model, and for each forecast, we run one case assuming an LNG import hub is built and LNG thermal resources are available (including conversion of various existing resources, with cost data provided by the Companies), and one in which no LNG hub is available. Thus, four cases were run for each island (LNG Market DGPV, LNG High DGPV, No-LNG Market DGPV, No-LNG High DGPV). All of these cases are run assuming that each utility must meet its own RPS constraint independently.

There were several other sensitivities tested. These sensitivities, some performed at the request of the Companies and some at the request of stakeholders, are listed below. To minimize the number of cases produced, these sensitivities, except when noted otherwise, were run using the No-LNG option with the Market DGPV forecast on each island.

- Value of renewable hedge: Ulupono requested that we investigate the sensitivity of the results to a 35% adder to all forecasted fuel prices on each island.

- No-RPS case: The Consumer Advocate requested that we develop a case in which there is no RPS constraint on each island for cost comparison to other cases.

- Enhanced renewable energy potential on Oahu: In the base cases, we use the National Renewable Energy Laboratory (NREL) produced estimates for solar and wind resource potentials on Oahu consistent with using land that has less than a 5% slope. Dr. Fripp, at the request of Ulupono and Blue Planet, has provided us data with increased resource potentials on Oahu consistent with using land up to a 10% slope.

- Paniolo pumped storage and wind plant: Paniolo requested that we substitute the company assumptions for their own cost and performance estimates of a pumped storage and wind resources on Hawai'i Island.

- Military units on Oahu: The base cases assume two military fuel oil units on Oahu (located at Marine Corps Base Hawaii and Joint Base Pearl Harbor-Hickam) will be in service in the early 2020's. A sensitivity case was run in which these units are not assumed to be in service, but the model is given the option of purchasing units of their equivalent size and efficiencies.

- DGPV as model choice: A scenario was run on each island in which the DGPV forecast is completed through 2020, but there is no DGPV forecasted beyond 2020. Instead, in the time-period beyond 2020 the model is given the option of procuring DGPV, similarly to the way in which the model is given the option to procure grid-scale solar or other renewable resources.

- Uncurtailable DGPV case: A scenario was run on each island in which all DGPV resources are assumed to be uncontrollable, as opposed to the base cases in which all DGPV installed after 2020 is assumed to be curtailable. These cases were run using the No-LNG High DGPV forecasts on each island.

Finally, in addition to the individual island cases we run a “Copperplate” case where we treat all three islands (Oahu, Maui, Hawai’i) as one large zone connected with infinite transmission capacity between the islands with no import or export limits. This case is run to investigate the maximum potential benefits of building interisland cables between these islands without regard to the cost of the cable itself. The case is useful as a screen to determine if the cable should be studied further and to determine changes in generation portfolios by island that have the potential to provide the most benefits.

Q5. PLEASE SUMMARIZE THE RESULTS.

A5. The findings are grouped into results of the Company defined cases and results of cases defined by stakeholders. Where possible, we have tried show only a set of simplified model output data to define and highlight the differences between the cases. This output data includes costs normalized to a base or reference case plan and proposed least cost investments over through 2045 designed to minimize the cost of compliance with the 100 percent RPS requirement by island and in the copper plate transmission case.

Results from Company Defined Cases

1. Since the Companies are not requesting an LNG import hub in the near term, the No-LNG cases are used as the reference cases on each island. In this document the No-LNG Market DGPV plan on each island is used as a common point of comparison between costs and build decisions across cases. The comparison of the costs of this plan with the costs of other plans is shown in Table 1 below. The costs of any two cases can be compared by their costs in relation to the No LNG, Market DGPV plan, which has a normalized net present value cost of 1. Table 1 below shows each of the reference case costs as 1 in the middle column of Table 1 below. Investments in LNG, given the EIA fuel price forecast with not hedge adder have lower costs and the higher DGPV forecasts are also higher costs than the reference cases.

Table 1. Total resource cost comparison between Company defined cases (normalized with respect to No-LNG Market DGPV case on each island)

Oahu	**Market DGPV**	**High DGPV**
No-LNG	1.00	1.05
LNG	0.92	0.97
Maui	Market DGPV	High DGPV
No-LNG	1.00	1.10
LNG	0.85	0.95
Hawaii	**Market DGPV**	**High DGPV**
No-LNG	1.00	1.18
LNG	0.85	1.05

2. Over the next five years, it is cost effective to take advantage of the federal tax incentives for renewable resources on each of the islands. This incentive drives the results that show that each of the company plans are ahead of the straight-line year by year RPS goal. On Maui and Hawai'i, this is true regardless of LNG status. On Oahu, the No-LNG case results in Oahu staying ahead of the RPS goal, but in the LNG cases Oahu does not significantly exceed the RPS goal.

3. Over the next five years, the amount of tax advantaged renewable energy chosen by RESOLVE is limited by the amount of renewable energy that Companies estimate can be interconnected and delivered safely to loads through 2020. This interconnection limit was estimated by the Companies to be 130MW of wind for Maui, 20MW of wind for Hawaii and 300MW of solar for Oahu; other renewable resources, such as solar on Maui and Hawaii, were not constrained by any interconnection limit, but were also not chosen by RESOLVE.

~~4.~~ Energy storage or some form of advanced demand response is cost-effective as early as 2020 for Hawaii and in 2022 for Oahu and Maui.

5. The Marine Corps Base Hawaii (MCBH) at Kaneohe Bay and the Joint Base Pearl Harbor-Hickam (JBPHH) were included as planned resources in the base cases. A sensitivity was run where the model was given the option to purchase those units, but they were not selected in the base thermal build; increased amounts of renewable energy (in the No-LNG cases) and other dispatchable LNG resources (in the LNG cases) were chosen to replace this capacity in the short term. In the longer term, in all cases some dispatchable thermal capacity was chosen in 2045.

   As we discuss in response to Question 6 below, the RESOLVE model does not investigate detailed contingencies or system security constraints, and there are reliability benefits to keeping sufficient levels of thermal projects online which RESOLVE is not considering. Furthermore, when RESOLVE chooses not to invest in the military based thermal resources, the model assumes that beyond 2020 there are no interconnection limits or land use issues to constrain the grid in absorbing further renewable energy installations and that all of these new resources, whether located behind or in front of the customer meter, are fully curtailable.

6. The interisland "Copper Plate" cable case substantially increases the renewable builds on the neighbor islands. For example, the proposed renewable resource build on Oahu in the 2020-2022 is reduced from 348 MW to 0; Maui increases from 96MW to 217MW; and, Hawaii increases from 70MW to 814MW. Note that these are unrealistic build amounts given both the near-term timing and the unlimited amounts of grid capacity assumed on each island system.

7. The interisland cable produces sufficiently large benefits related to procurement and energy and capacity savings that we recommend Hawaii continue to conduct more detailed focused analysis on specific configurations that would provide a combination of maximum net benefits and renewable procurement flexibility. Using our screening process, we estimate that a large cable system interconnecting each island could have benefits as large as three billion dollars in present value over the lifetime of the cable. A phase 2 study of the interisland cables would break down the copperplate case into

scenarios that would include (1) specific transmission project costs and operating limitations, and (2) assumptions about the feasibility, timing, and cost constraints of significantly expanded renewable resources on Maui and Hawaii.

In the near term, the resource decisions in the interisland cable case versus the individual island cases do not change on Maui or the Big Island. While the interisland cable case identifies greater renewable build on these islands due to better resource qualities over the long term, the renewable build is constrained by interconnection limitations on each of the islands in the early years. In addition, given the uncertainty of the Phase 2 study findings, we do not recommend that Hawaii conduct its procurement and transmission planning on the individual islands today as if the cable were going to be in place. To avoid any risk of stranding capital investments, we believe that a safer more prudent approach would be focus on optimizing the plans for each island separately over the next 5 years..

8. A number of stakeholders were concerned that the company request for approval in the first 5 years not commit it to an inflexible longer term pathway. In general, we believe that the RESOLVE choices in the first 5 years are fairly robust and provide what now looks like a unique and quickly vanishing opportunity to take advantage of federal tax incentives to benefit electricity consumers. We strongly recommend that Hawaii take maximum advantage of these subsidies as soon as possible.

   Parties asked if anything recommended in the first years would change if we know that the cable were going to be constructed later. There is a change in the portfolios. In the interisland cable case, RESOLVE wants to build less grid scale solar first 5 years in favor of lower cost and higher quality wind on the neighbor islands. However, given the uncertainty around the cable feasibility and timing, and the potential fleeting opportunity of the tax subsidies, the cost of overbuilding tax subsidized solar early is relatively small and a risk of counting on an uncertain future cable can be quite large. More impactful differences in resource decisions start to occur in 2022. We recommend that these resource choices be analyzed in detail in future planning rounds, with more development of the cost assumptions and operational constraints of the cable options.

9. Letting the model choose to build DGPV beyond 2020 results in lower DGPV buildout than the market DGPV forecast. On Oahu, the decrease of DGPV over the market DGPV forecast results in increased build of grid-scale solar resources, which are less expensive than DGPV on a total resource cost basis. On Maui there are increasing amounts of both grid-scale solar and wind, whereas on Hawai'i the wind resource is sufficiently dominant over the other options that the market forecast DGPV is completely replaced with wind.

10. Companies asked us to assume that all DGPV installed beyond 2020 is fully curtailable. If we remove this assumption, the model builds more battery resources throughout the plan. The cost differences over the high DGPV curtailable case are material and grow over time. Moreover, our modelling assumes that the system operator can operate the system with perfect foresight under normal operating conditions. Under more strenuous, information poor conditions, the operator is going to have to curtail larger quantities of energy than we estimate. If curtailment control is limited, there a possibility that reliability can be jeopardized. We want to highlight the curtailment assumption for all new post 2020 DGPV because we believe that renewable curtailment for all resources is a fundamental renewable integration tool that our modelling assumes and uses to minimize projected costs.

Results from Stakeholders' Cases

11. Ulupono asked us to run a case where LNG costs were higher by 35% to reflect a fuel price hedge against future volatility that would naturally be avoided with investments in renewable resources. The results are similar to those from the No-LNG case, where fuel prices are approximately double those in the LNG scenario per MMBTU. The Companies have an economic incentive to interconnect as much tax advantaged renewable resources as they can before the federal tax incentives expire. Under Internal Revenue Service (IRS) rules, a facility will be considered to satisfy the Continuity Safe Harbor if it is placed in service during a calendar year that is no more than four calendar years after the calendar year in which construction of the facility began[1]. Thus, the Companies have an incentive to begin construction of tax advantaged renewable resources before they are strictly needed as the construction can be completed up to four years later and still allow the facility to receive federal subsidies.

12. Hawaii Gas asked us to run a case using a Hawaii Gas produced LNG price forecast on Oahu Island, with no LNG on the neighbor islands. The LNG price forecast from Hawaii Gas was based on a volume assumption of 0.9 MTPA with a price of $12.32/MMBTU in 2022 (this price, in $2016, represents the "total cost" of LNG import including delivery to power plant; it does not include power plant conversion costs, which are included separately), a high of $13.06/MMBTU in 2030, and decreasing back to $12.66/MMBTU in 2040. The resulting build is similar to the HECO LNG Market DGPV case results, and in the first five years there are effectively no differences in thermal and renewable procurement decisions.

13. Dr. Fripp, on behalf of Ulupono, requested that we include additional solar and wind resources on Oahu by extending the supply estimates produced by NREL. The base

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[1] https://www.irs.gov/pub/irs-drop/n-16-31.pdf

cases were limited to 164 MW of onshore wind and 2756 MW of utility scale solar; the increased supply estimates include smaller and potentially higher cost sites and have total resource potentials of 2680 MW of onshore wind and 6583 MW of utility scale solar. We did not have accurate estimates of costs for these sites, but the addition of these new sites increased the early renewable build for wind on Oahu, from 30 MW to 370 MW in 2022, assuming no additional development costs per kWh of output. This increase can be attributed to the higher capacity factors of the best resource tranche relative to the average capacity factor used in the Companies reference case. However, this significantly larger renewable build is still limited by the near-term interconnection limits on the system.

14. Paniolo asked us to substitute their own estimates of performance and costs for 6-hour pumped-storage hydro (PSH) and wind for the input assumptions given to us by the Companies for the base cases. The Paniolo performance characteristics showed higher capacity factors for the wind resource and similar resource costs for both wind and PSH when compared to the Companies assumptions for the same resources. However, the resource cost of PSH remained significantly more expensive than 4-hour batteries. In the Companies base case runs, the PSH is an option but never selected due to its relatively high costs compared to batteries. Paniolo wanted to see the impact on total costs of including their project. To derive this result, we forced the model to take the combination of 30 MW of wind and 30 MW of PSH in 2022, per the Paniolo specifications. As a result, the Paniolo PSH displaces some of the RESOLVE battery build decisions throughout the planning horizon, but at a higher capital cost due to both the increased capacity (30 MW of PSH versus 14 MW batteries in 2022 in the base case) and higher unit cost of the PSH when compared to batteries. The Paniolo sensitivity is approximately 13 percent higher than the Company base case plan.

15. DBEDT requested that we develop a process to use RESOLVE to test the robustness of our findings. DBEDT's main concern was with regard to the proposed 5-year plan and anything that might change in it that was sensitive to long term forecasts of uncertain variables. We discussed the following four uncertain variables in our analysis: fuel price forecasts, renewable price forecasts, storage price forecasts, and the impact of the interisland transmission cable. Because LNG was not being requested in the 5-year plan and RESOLVE did not recommend new thermal resources in the 5-year plan, DBEDT only requested that we look at whether the cable would change the 5-year recommended plan. We confirmed with DBEDT in our follow up call that the copper plate cable case only increased the amount of renewable build on the neighbor islands in the five-year plan. The renewable build on the neighboring islands will already be constrained during the five-year plan by the amount of renewables interconnectable during that time period, thus there will be no difference in renewable build on Maui

and the Big Island. However, we do agree with DBEDT that the cable is a potential game changer for the longer-term plan.

The types of renewable build the model selects do change with the interisland cable. Oahu has reduced grid scale solar build, for example, in the cable case in the first 5 years. We recommend following the individual island case build cases for two reasons. First, there is a substantial level of uncertainty regarding cable feasibility and timing. Second, over the next decade, we don't see a substantial loss of renewable build on Oahu being replaced with low cost renewables on the neighbor islands because of the near-term interconnection and integration constraints.

16. DBEDT also requested a sensitivity on the inclusion of the military units in the reference case. The Marine Corps Base Hawaii (MCBH) at Kaneohe Bay and the Joint Base Pearl Harbor-Hickam (JBPHH) were included as planned resources in the base cases. A sensitivity was run where the model was given the option to purchase those units, but they were not selected in the base thermal build; increased amounts of renewable energy (in the No-LNG cases) and other dispatchable LNG resources (in the LNG cases) were chosen to replace this capacity.

    As we discuss in response to Question 6 below, the RESOLVE model does not investigate detailed contingencies or system security constraints, and there may be reliability and other benefits to keeping these projects online which RESOLVE is not considering. Furthermore, reliance on additional renewables to replace these units is contingent on being able to install and fully integrated those renewables in the near term. Getting the transmission in place to do so is uncertain and MCBH and PBPHH units would increase the flexibility of the system while transitioning to greater reliance on renewables.

17. Finally, we developed the single lowest cost plan for the Consumer Advocate (CA Sensitivity) that did not comply with the RPS and utilized LNG/Market DG. These lowest cost plans were run under both No-LNG and LNG conditions, utilizing the Market DG forecast. In all cases, the plans are less expensive than the individual island Market No-LNG RPS-constrained base cases, but by only a small amount. In the last cost plan on both Maui and Hawaii gets you to nearly a 100 percent RPS compliant portfolio by 2045.

18. Table 2 below shows normalized costs for each individual island's Non-RPS constrained bases.

    Table 3 below shows the portion of annual electricity coming from RPS-eligible sources. Note that in the No-LNG cases a significant portion of electricity is being sourced from renewable resources, even without an RPS constraint, because the economics of renewable sources are favorable.

Table 2. Costs for Consumer Advocate No-RPS constraint cases, normalized with respect to No-LNG Market DGPV cases

Oahu	No-RPS Market DGPV
No-LNG	0.87
LNG	0.84
Maui	**No-RPS Market DGPV**
No-LNG	0.99
LNG	0.80
Hawaii	**No-RPS Market DGPV**
No-LNG	0.98
LNG	0.81

Table 3. Portion of annual electricity from RPS-eligible sources, in Consumer Advocate No-RPS constraint cases.

Oahu	2020	2022	2025	2030	2035	2040	2045
No-LNG	34%	41%	50%	55%	61%	66%	72%
LNG	28%	29%	31%	34%	35%	34%	45%
Maui	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
No-LNG	54%	72%	73%	75%	74%	83%	95%
LNG	45%	64%	63%	65%	63%	63%	67%
Hawaii	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
No-LNG	63%	71%	76%	78%	79%	80%	95%
LNG	63%	76%	78%	80%	79%	80%	76%

Q6. DO YOU HAVE ANY CAVEATS REGARDING YOUR FINDINGS?

A6. Yes, performing the variety of cases analyzed using an optimal expansion planning model required that we use a simplified planning reserve margin (PRM) measure of reliability for plans that require high amounts of variable energy resources, and estimates of operating reserves. We also did not model transmission networks, stability constraints, or contingency requirements. The Companies are supplementing our analysis with modelling using the PLEXOS simulation model and analysis performed by Ascend Analytics to address these limitations. The Companies are also performing system security analyses to determine minimum inertia, fast frequency response, primary frequency response and fault current needed to maintain stable and reliable isolated island grids. However, even the collection of these models does not adequately stress the reliability of each high renewable plan over time.

The assumptions that define each case are necessarily simplifying for several reasons:

- The system operating requirements for reliable service in the future are currently uncertain. Between now and 2045, the technologies at grid scale and behind the meter will change significantly, requiring new operating procedures and reliance on new technologies such as storage for grid services previously met with thermal generation. The assumptions used to define the need for ancillary services in RESOLVE are therefore more certain in early years when the system is still relatively familiar, and less certain in later years when significantly more renewables and other novel technologies are installed. The rate with which the system changes differs by island, depending on the relative economics of different resource options.
- RESOLVE does not include detailed power flow and stability analysis that would consider transmission networks, unit reliability, and contingency measures.
- The computational complexity of capacity expansion and hourly dispatch logic in RESOLVE means that additional detailed transmission network constraints would significantly slow down the model. Furthermore, many of the constraints around reliability are not quantified by a simple formula suitable for modeling. RESOLVE is an appropriate combination of complexity and runtime such that many iterations and sensitivities can be run to determine least cost resource portfolios through to 2045 and inform the more detailed, near term HECO modeling effort.
- RESOLVE does not incorporate the complex contract structures with existing renewable resources. All renewable resources in RESOLVE are assumed to recover their full capital cost over their lifetimes and incur only variable costs per MWh generated.
- The RESOLVE input datasets do not include more detailed generator characteristics such as “black start”, maintenance schedule, generator reliability etc.
- RESOLVE can identify when a generator is no longer needed under normal operation conditions according to Companies’ reserve constraints. However, without considering the more detailed generator characteristics, power flow implications, and contingency constraints, RESOLVE can only act as a guide to identify candidate units for removal from service. Whether a unit is removed from service is therefore addressed in the Plexos modeling.

Given these limitations of the results, the RESOLVE least cost resource plans act as a guide and starting point for the Company team. Although we believe that our results are unbiased with regard to technology choice and suitable for the economic comparison between the different plans, we recommend that the Companies, working closely with key stakeholders, regulators, and state agencies, continue to refine their long-term planning models and data to incorporate more real world operational constraints. We do not recommend the use of the RESOLVE cases by themselves be used to make permanent plant retirement decisions.

Q7. HOW IS THIS DOCUMENT ORGANIZED?

A7. In Section 2 we describe the overall results of the base case scenarios we were asked to develop for the Companies using the input data and assumptions define by the Companies. Section 3 then lays out the sensitivity case for the base case scenarios. Section 4 describes the sensitivity cases that we put together for third parties who requested and defined them. Finally, an attached appendix contains the input assumptions that were used to define each of the RESOLVE cases described below.

2: COMPANIES BASE CASE

Q8. PLEASE DESCRIBE THE KEY DIFFERENCES IN THE ASSUMPTIONS USED TO DEFINE THE COMPANY BASE CASES.

A8. The base case for each island is the No-LNG option using the "Market" DGPV forecast for installed DGPV. All installed DGPV through 2020 are assumed to be uncontrollable and uncurtailable, whereas all DGPV resources installed beyond 2020 are allowed to be economically curtailed if required. This is a critical assumption that allows us to minimize the costs of these high renewable energy cases.

Q9. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE BASE CASES.

A9. Capacity graphs show installed capacities aggregated by resource type. The capacities shown in the graph are resources which the model utilizes for either energy or to meet PRM purposes. There are some resources which the model does not find necessary to use under normal operating conditions and, while on the system, are not displayed on the utilized capacity graphs. These resources are potential candidates for deactivation and further study for potential retirement if found to be unnecessary for system needs in the more detailed modeling performed by the Companies. The breakdown between utilized capacity and un-utilized capacity can be seen in the Appendix. As addressed in Q6 please note that normal operating conditions, while including contingency reserve and operating reserve constraints as specified by the Companies, are not meant to encapsulate system security and contingency conditions, and therefore the RESOLVE results should not be taken to mean that a resource whose capacity is not being utilized should be retired. For the main takeaways from these base case results see Q10.

Figure 1. Utilized installed capacity for Oahu No-LNG Market DGPV case

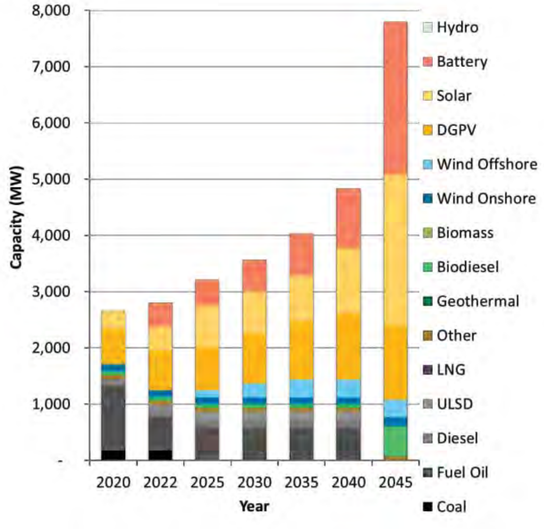


Figure 2. Utilized installed capacity for Maui No-LNG Market DGPV case

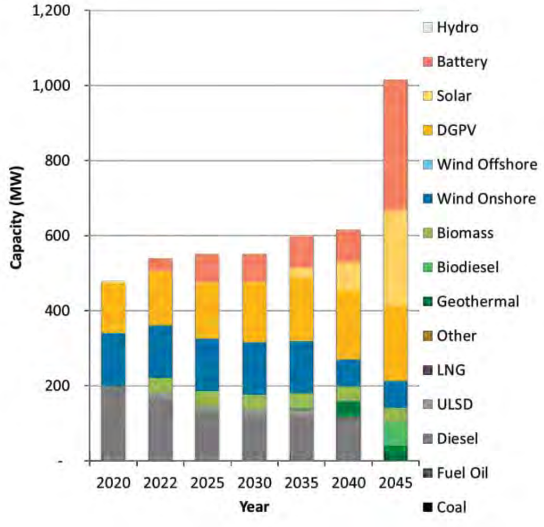
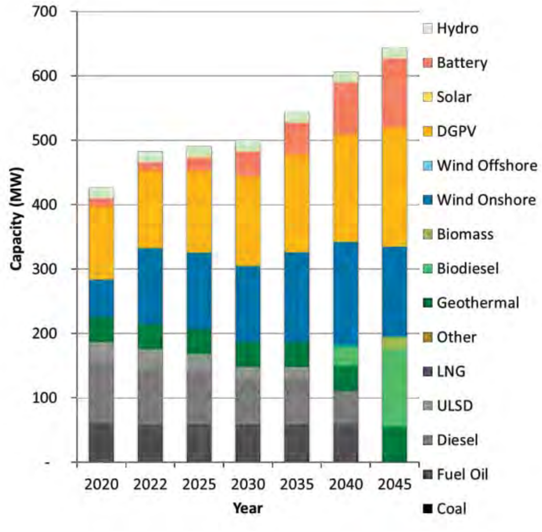


Figure 3. Utilized installed capacity for Hawai'i Island No-LNG Market DGPV case



Q10. WHICH OF YOUR MAIN FINDINGS DID YOU REACH BASED ON YOUR BASE CASE ANALYSIS AND PLEASE HIGHLIGHT THE RESULTS THAT YOU RELIED ON TO SUPPORT THOSE FINDINGS?

A10. On all islands, during the first five years (through 2022), RESOLVE moves aggressively to build renewable resources. This is especially pronounced on Hawai'i Island and Maui, where there is a markedly increased amount of wind built in 2022. RESOLVE is moving to take advantage of tax-credited renewable resources early, but is constrained in its ability to do so by interconnection constraints (as stated in Q5 above, the interconnection limits modeled here are maximum additional renewable resources by 2020 of 130MW of wind for Maui, 20MW of wind for Hawaii, and 300MW of solar for Oahu).

On all islands, there are no new thermal resources selected by RESOLVE beyond those already planned to be in service. On Oahu in particular this result is true assuming that the military units (MCBH and JBPHH) are planned to be in place by 2022 and 2025.

On all islands, the value of renewable resources relative to thermal resources rises over the study horizon, so the conventional thermal fleet size decreases. There is a slight uptick on Hawai'i in 2045 as there is more biodiesel capacity in 2040 than conventional oil capacity in 2040. This is because as there are some underutilized resources which are converted to biodiesel in 2045. These biodiesel resources are used primarily for capacity to meet PRM; the majority of RPS-eligible energy comes from wind, with DGPV and geothermal sources filling in the rest.

Oahu and Maui see a “hockey stick” like build in which the last year sees a large amount of energy storage built. This large build late build is due to: 1) the large increase in RPS from 70% in 2040 to 100% in 2045; 2) the high cost of biodiesel (nearly 2x the cost of conventional diesel); and 3) the steeper decrease in battery costs relative to the pace of cost changes for other resources. Nevertheless, batteries (representative of energy storage and other demand response more broadly that can provide the same services) are cost effective as early as 2020 on Hawai’i and 2022 on Maui and Oahu.

3: COMPANIES SENSITIVITIES

Q11. PLEASE DESCRIBE THE INPUT ASSUMPTIONS USED TO DEFINE THE COMPANIES SENSITIVITY CASES

A11. In addition to the base case, the Companies identified several sensitivity cases. The list of the Companies-defined sensitivities are defined below, with more details in each case results section.

1. No-LNG with “High” DGPV Forecast: Use the “High” DGPV forecast on each island instead of the “Market” DGPV forecast.
2. LNG with “Market” DGPV Forecast: Allow the model to procure LNG resources after 2022, with the option of converting various existing thermal generators. Cost data for this conversion is provided by the Companies. The LNG fuel is available starting in 2022, but not available in 2045.
3. LNG with “High” DGPV Forecast: Similar to the LNG with “Market” DGPV forecast, but with the “High” DGPV forecast on each island.
4. DGPV as an endogenous choice: Model is given the option of procuring DGPV resources, with cost data for the DGPV resources provided by the Companies. The DGPV installed through 2020 is assumed to be still on the system.
5. DGPV as uncurtailable: Model is run using No-LNG “High” DGPV forecast on each island, but all DGPV installed after 2020 are not assumed to be curtailable.
6. Copperplate with “Market” DGPV Forecast: Assume all islands are connected with infinite capacity, infinite reliability transmission cables.

Q12. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE SENSITIVITY CASES

A12. For each sensitivity case, we present a capacity chart and a normalized cost table with entries for each evaluation year.

Capacity graphs, as described in Q9, show utilized installed capacities for each case, aggregated by resource type.

Cost tables compare the cost of the cases relative to the base cases as defined in Q9: No-LNG Market DGPV forecast cases. Values greater than 1.00 signify the cost for the sensitivity case in question is greater than that of the No-LNG Market DGPV case. The costs reported by RESOLVE and summarized in these tables are for the cumulative incremental resource build and the cumulative total system operating and O&M costs up to the year in question. Costs are reported on a total resource cost basis. The total cost at the end of the time horizon of the base case under this definition is $10.6 billion on Oahu, $1.7 billion on Maui, and $1.1 billion on the Big Island.

1. No-LNG with High DGPV Forecasts

The No-LNG "High" DGPV cases were run using the same input assumptions as each of the islands' base cases, with the substitution of the "High" DGPV forecast instead of the "Market" DGPV forecast.

On Oahu, the difference between this case and the base case is mostly cost, as the more expensive DGPV resources are built instead of lower cost grid-scale solar resources. Table 4 below, for example, shows that the High DGPV case has higher cost renewables by 12% and higher costs storage by 3% by 2045 compared to the No-LNG Market DGPV case. The total cost of this case is 5% higher than the market DGPV case by 2045.

On the neighbor islands, the mix of resources changes more significantly. On Maui, the increased DGPV forecast results in much higher capital costs of renewable energy (157%) and decreased grid-scale solar and grid-scale wind build. The Hawaii case has even more DGPV in the high case, which shows an even higher renewable energy capital cost (189% for the capital cost of renewable energy) compared to grid-scale wind in the Hawaii base case.

On all islands the High DGPV cases have a higher total resource cost than the Market DGPV cases, which is consistent when the higher cost and lower capacity factors of DGPV resources compared to the alternative grid-scale renewable resources.

Oahu Results

Figure 4. Utilized installed capacity for Oahu No-LNG High DGPV case

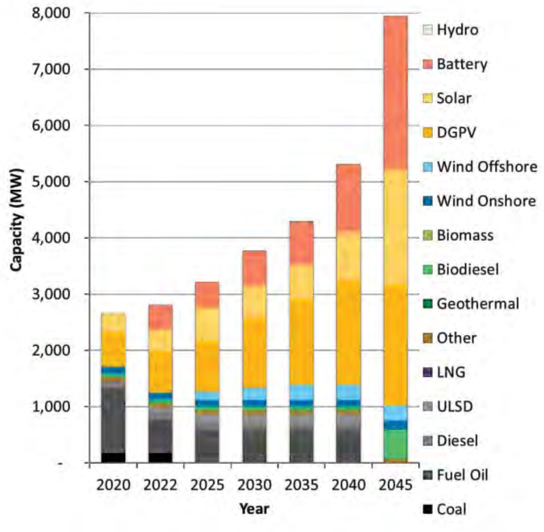


Table 4. Cumulative total resource cost for the Oahu No-LNG High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	1.00	1.00	0.99	0.99	0.99	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.02	1.06	1.08	1.10	1.14	1.12
Battery							
Capital	0.00	1.00	1.00	1.02	1.03	1.04	1.03
Total	1.00	1.00	1.01	1.02	1.03	1.04	***1.05***

Maui Results

Figure 5. Utilized installed capacity for Maui No-LNG High DGPV case

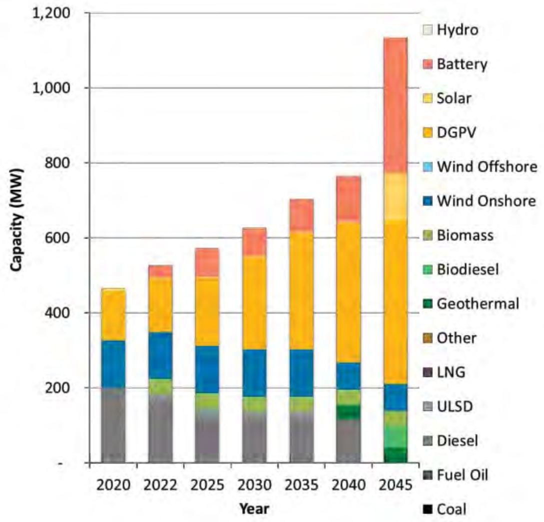


Table 5. Cumulative total resource cost for the Maui No-LNG High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.06	1.06	1.04	1.01	1.00	1.00	0.99
Fixed	1.00	1.00	1.00	1.00	0.99	0.99	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.81	0.82	0.98	1.20	1.38	1.57	1.57
Battery							
Capital	0.00	0.94	0.98	0.99	0.99	1.03	1.04
Total	1.01	1.00	1.01	1.03	1.06	1.09	***1.10***

Hawai'i Island Results

Figure 6. Utilized installed capacity for Hawai'i Island No-LNG High DGPV case

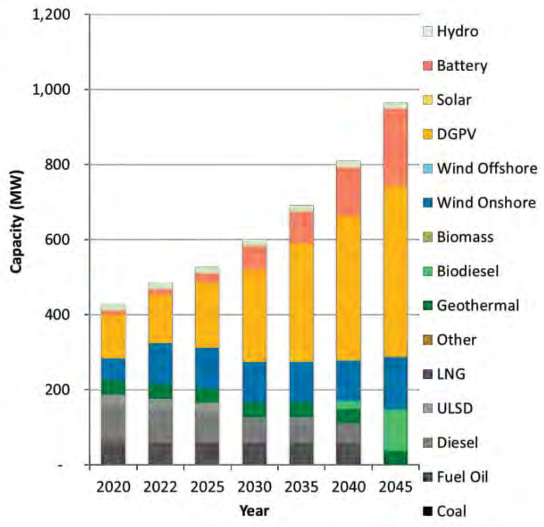


Table 6. Cumulative total resource cost for the Hawai'i Island No-LNG High DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	0.99	1.01	0.99	0.96	0.95	0.94	0.93
Fixed	1.01	1.00	1.00	0.98	0.97	0.97	0.72
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.01	1.20	1.43	1.61	1.75	1.89
Battery							
Capital	0.97	0.97	1.05	1.24	1.34	1.39	1.50
Total	1.00	1.01	1.03	1.08	1.12	1.17	***1.18***

2. LNG with Market DGPV Forecasts

The LNG "Market" DGPV cases were run allowing the model to procure LNG resources. We give the model the option of converting various existing generators or maintaining the fuel oil versions of those generators, with cost data for this conversion provided by the Companies. The choice of LNG conversion occurs in 2022, the COD year for the LNG import hubs and when LNG is available as a fuel option.

On all islands, no new LNG power plants are built, but a number of existing large generators are fuel-switched; on Maui and Hawai'i these are the large dual train combined cycle plants - Maalaea and Keahole, respectively. On Oahu, the LNG converted plants include the Kalaeloa Partners (KPLP) plant, and some amount of the newer Kahe steam turbines. The precise units which are converted should be decided on the basis of conversion costs, expected reliability, and system security constraints.

The value of the LNG resource to each island is dependent in part on the cost of the LNG fixed infrastructure costs. The cost of the plant unit conversions is born by the island in question, but there is some uncertainty in the allocation of the cost of the LNG import hub and ISO container infrastructure to each island. As a first pass to use in the RESOLVE cases, we have allocated all of the cost of the LNG import fixed infrastructure pieces to Oahu, as Oahu has the largest LNG demand and the greatest absolute cost reduction when LNG is available. However, this means that the relative benefits on Oahu are lower than they would be if the cost of the hub was split among islands; similarly, the relative benefits of LNG on Maui and Hawai'i are greater than they would be if the cost of the hub was apportioned to those islands as well. Thus, the relative cost savings of an LNG import hub listed below are a lower bound on Oahu and an upper bound on Maui and Hawai'i.

Another cost difference worth highlighting is that of the thermal fixed costs. The thermal fixed costs on Oahu are quite large, ranging from 3.27 (see table below; note these are relative costs) in 2022 to 5.76 in 2045. The thermal fixed cost is the fixed cost of thermal resources in the LNG case normalized to the fixed cost of the thermal resources in the Non-LNG case. The LNG case thermal resources includes the cost of the LNG fixed infrastructure, which is a cost of nearly $300 million annually. In addition to this, the thermal fixed costs include the conversion cost of the individual power plants on Oahu. Finally, the fixed cost of the No-LNG cases includes only the avoidable fixed O&M costs for the existing thermal resources; the RESOLVE framework includes incremental resource costs only, so if there are any fixed sunk costs which cannot be avoided by making different decisions, then those costs are not included in the fixed cost as described below.

As various thermal resources retire the No-LNG case fixed thermal cost declines, whereas in the LNG case the annualized cost of the LNG hub and the annualized cost of the LNG conversion stays constant for the lifetime of the resources (20 years). This means the LNG thermal fixed cost stays nearly constant, but when calculating the ratio cost difference between cases, it is divided by a No-LNG case base case cost that is decreasing over time; this results in the relative cost of the LNG thermal fixed cost component appear to increase over time. Thus, because of a combination of (1) large LNG hub fixed infrastructure costs; (2) constant annualized cost of LNG hub and conversion cost; (3) low fixed costs for continuing non-LNG resources; and (4) the

RESOLVE optimization framework which minimizes the incremental total resource costs, the thermal fixed infrastructure cost in the Oahu LNG case is large and increasing in comparison to the No-LNG case.

By contrast, the renewables and thermal variable cost components in the Oahu LNG cost table are both below one. However, the amount of renewable resources and the amount of fuel burn are so large that these cost components more than out-weigh the increased cost of the thermal fixed resource cost component, so that the total relative resource cost for the LNG case is significantly below that of the Non-LNG case. For all three islands, the LNG case is substantially lower in total cost than the Non-LNG base case.

Oahu Results

Figure 7. Utilized installed capacity for Oahu LNG Market DGPV case

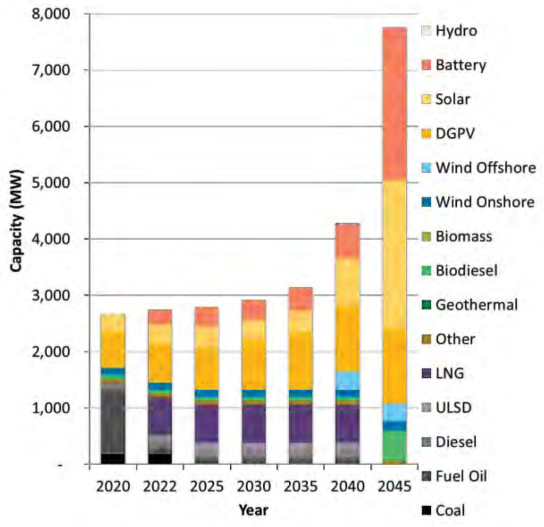


Table 7. Cumulative total resource cost for the Oahu LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.81	0.73	0.70	0.68	0.65	0.67
Fixed	1.00	3.27	4.79	5.63	6.04	6.27	5.76
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.90	0.58	0.48	0.46	0.54	0.67
Battery							
Capital	0.00	0.60	0.69	0.67	0.66	0.64	0.76
Total	1.00	1.01	0.97	0.94	0.91	0.91	***0.92***

Maui Results

Figure 8. Utilized installed capacity for Maui LNG Market DGPV case

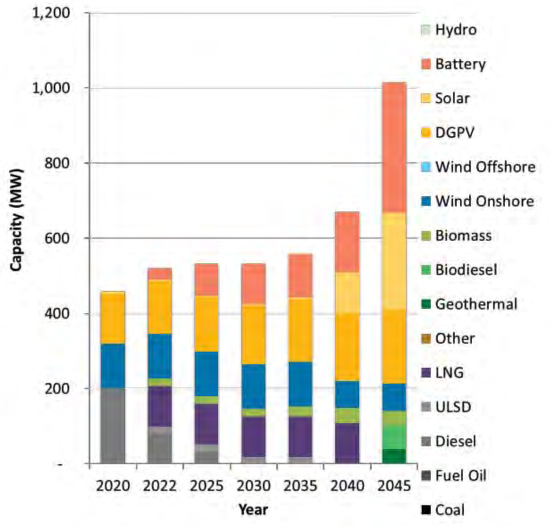


Table 8. Cumulative total resource cost for the Maui LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.10	0.97	0.89	0.82	0.77	0.75	0.76
Fixed	1.00	0.99	0.97	0.93	0.92	0.86	0.89
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.70	0.72	0.73	0.74	0.74	0.78	0.84
Battery							
Capital	0.00	0.87	1.04	1.16	1.19	1.25	1.17
Total	1.02	0.94	0.89	0.86	0.83	0.82	***0.85***

Hawai'i Island Results

Figure 9. Utilized installed capacity for Hawai'i Island LNG Market DGPV case

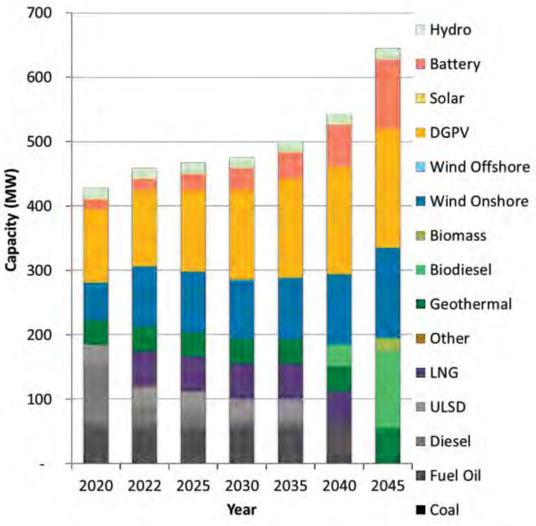


Table 9. Cumulative total resource cost for the Hawai'i Island LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.90	0.82	0.76	0.73	0.71	0.73
Fixed	0.97	1.15	1.24	1.29	1.32	1.33	1.23
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.78	0.76	0.76	0.75	0.75	0.80
Battery							
Capital	1.19	1.19	1.18	1.09	1.04	1.00	1.00
Total	1.00	0.93	0.89	0.86	0.83	0.82	***0.85***

3. LNG with High DGPV Forecasts

The LNG with High DGPV forecast shows decreased solar and grid-scale renewable sources on all islands, which is consistent with the No-LNG High DGPV case. In addition, there are fewer batteries before 2040 compared to the No-LNG cases, as the LNG resources can be used to provide power during low renewable output hours. However, the final build of 2045 is similar to that of the No-LNG High DGPV forecast, as all islands have a large battery build and biodiesel conversion of various existing resources.

Oahu Results

Figure 10. Utilized installed capacity for Oahu LNG High DGPV case

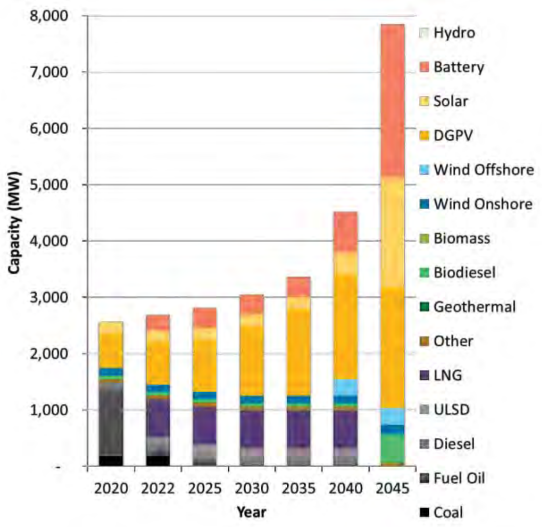


Table 10. Cumulative total resource cost for the Oahu LNG High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.05	0.85	0.76	0.72	0.69	0.66	0.68
Fixed	1.04	3.29	4.81	5.63	6.03	6.26	5.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.61	0.65	0.51	0.51	0.56	0.67	0.79
Battery							
Capital	0.00	0.67	0.72	0.70	0.66	0.66	0.77
Total	1.00	1.02	0.98	0.96	0.94	0.96	***0.97***

Maui Results

Figure 11. Utilized installed capacity for Maui LNG High DGPV case

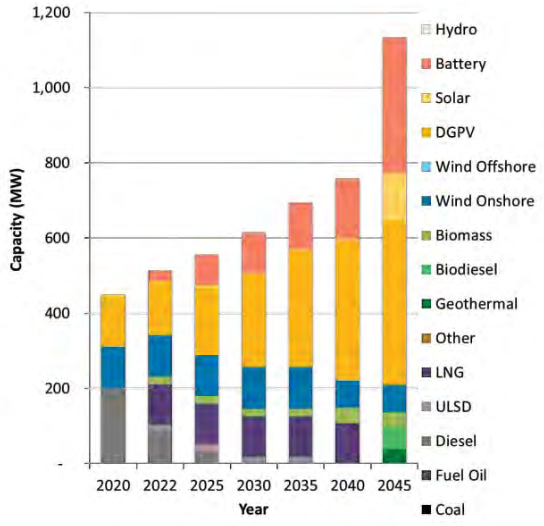


Table 11. Cumulative total resource cost for the Maui LNG High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.14	1.01	0.91	0.82	0.76	0.74	0.75
Fixed	1.00	1.01	0.98	0.93	0.91	0.85	0.88
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.58	0.60	0.77	1.00	1.20	1.41	1.45
Battery							
Capital	0.00	0.76	1.00	1.14	1.19	1.26	1.19
Total	1.02	0.94	0.91	0.90	0.90	0.91	***0.95***

Hawai'i Island Results

Figure 12. Utilized installed capacity for Hawai'i Island LNG High DGPV case

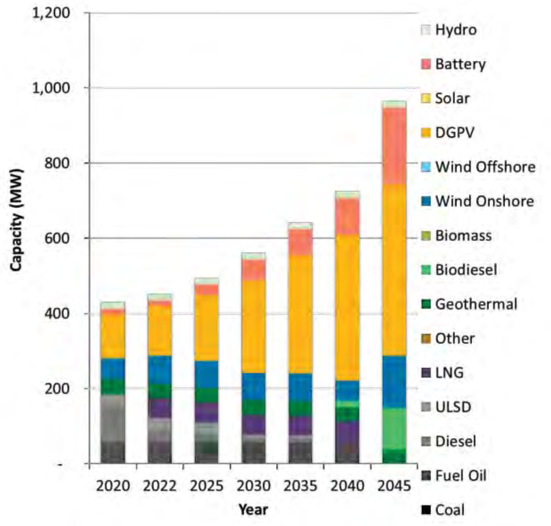


Table 12. Cumulative total resource cost for the Hawai'i Island LNG High DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	0.99	0.93	0.85	0.77	0.73	0.70	0.70
Fixed	0.97	1.15	1.24	1.27	1.29	1.30	0.94
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.72	0.86	1.10	1.30	1.45	1.65
Battery							
Capital	1.17	1.17	1.24	1.32	1.34	1.33	1.45
Total	0.99	0.94	0.92	0.94	0.97	1.00	***1.04***

4. DGPV as Endogenous Model Choice

In the following cases, the forecasted DGPV build by 2020 is left as is, but all DGPV beyond 2020 is left as a model decision. On each island, there is no DGPV resource built after 2020, as grid-scale renewable resources are cheaper and higher quality than the DGPV resources. On Oahu and Maui, the difference is largely within resource category, as DGPV is replaced with more solar. On Hawai'i Island, the wind resource is of sufficient capacity factor that the DGPV is replaced by wind capacity instead of grid-scale solar capacity.

Oahu Results

Figure 13. Utilized installed capacity for Oahu No-LNG Endogenous DGPV case

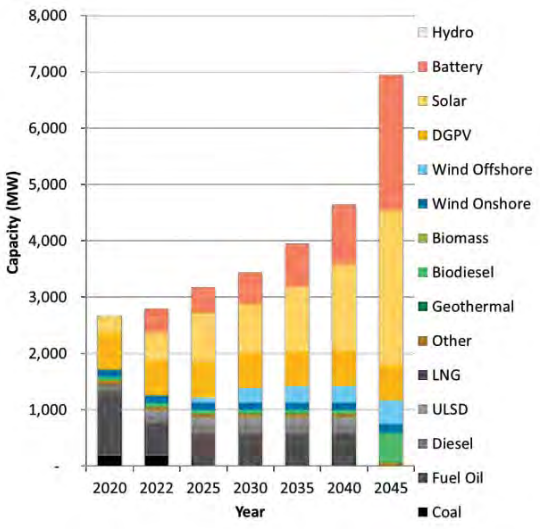


Table 13. Cumulative total resource cost for the Oahu No-LNG Endogenous DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	1.00	1.01	1.01	1.01	1.01	1.03
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.97	0.94	0.94	0.91	0.88	0.89
Battery							
Capital	0.00	1.00	1.00	0.99	1.00	1.00	0.96
Total	1.00	0.99	0.99	0.99	0.98	0.97	***0.97***

Maui Results

Figure 14. Utilized installed capacity for Maui No-LNG Endogenous DGPV case

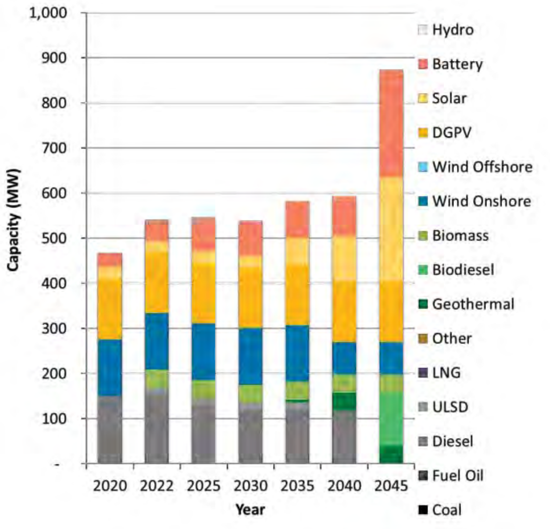


Table 14. Cumulative total resource cost for the Maui No-LNG Endogenous DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.99	0.99	1.00	1.00	1.00	1.13
Fixed	0.64	0.82	0.89	0.91	0.94	0.95	0.95
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.04	0.99	0.96	0.91	0.88	0.84	0.80
Battery							
Capital	*Div by 0*	3.00	1.63	1.42	1.29	1.26	1.06
Total	0.97	0.98	0.98	0.98	0.98	0.97	***1.00***

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Hawai'i Island Results

Figure 15. Utilized installed capacity for Hawai'i Island No-LNG Endogenous DGPV case

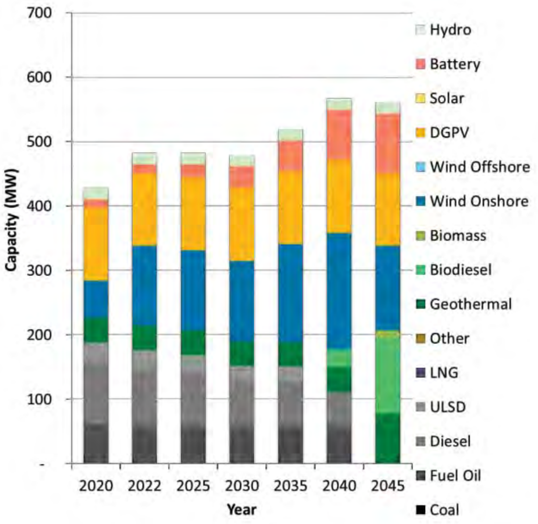

Table 15. Cumulative total resource cost for the Hawai'i Island No-LNG Endogenous DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.99	1.00	1.00	1.00	1.01	0.99
Fixed	1.00	1.00	1.00	1.01	1.01	1.01	1.15
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.98	0.94	0.90	0.86	0.82	0.77
Battery							
Capital	0.99	0.99	0.99	0.96	0.96	0.96	0.94
Total	1.00	0.99	0.99	0.98	0.97	0.96	***0.96***

5. Uncurtailable High DGPV

In the base case, we assume that all DGPV installed after 2020 is controllable. Curtailing DGPV in future years is a useful and valuable integration mechanism that reduces system costs. To investigate how valuable curtailment of DGPV is, we ran the bookend case on DGPV controllability, assuming all DGPV installed over the model time horizon is uncontrollable. This increases the amount of batteries built over the base case. On Oahu, the table below shows the relative costs of resources selected versus the base case. By 2045, an additional 19% cumulative investment in batteries is made over the base case to integrate the uncontrolled DGPV. Overall, the cost of the uncontrolled DGPV case on Oahu is 6% higher in 2045 than the base case. Similarly, we see significantly higher battery builds on Maui and Hawai'i Island, with increases of 9% and 19% in total cumulative cost by 2045, respectively.

Oahu Results

Figure 16. Utilized installed capacity for Oahu No-LNG Uncurtailable High DGPV case

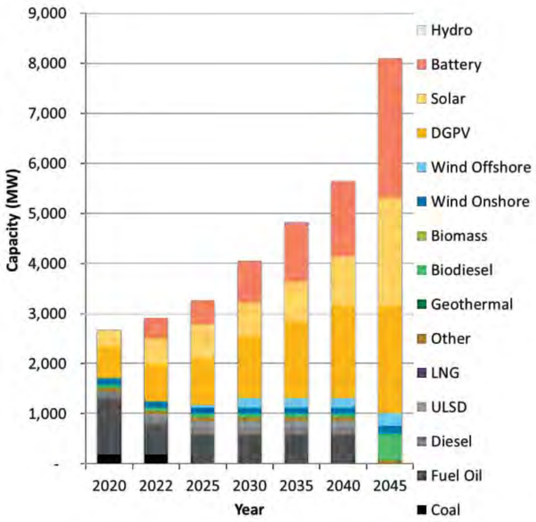

Table 16. Cumulative total resource cost for the Oahu No-LNG Uncurtailable High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.98	1.01	1.00	1.00	1.00	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.14	1.02	1.06	1.08	1.12	1.11
Battery							
Capital	0.00	1.00	1.03	1.16	1.23	1.26	1.19
Total	1.00	1.00	1.02	1.03	1.04	1.06	***1.06***

Maui Results

Figure 17. Utilized installed capacity for Maui No-LNG Uncurtailable High DGPV case

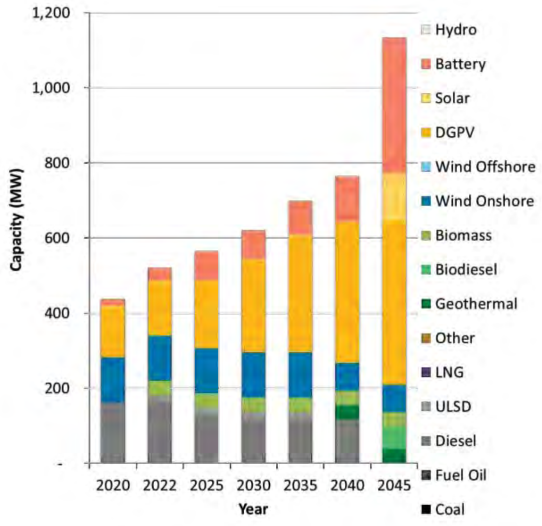

Table 17. Cumulative total resource cost for the Maui No-LNG Uncurtailable High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.08	1.08	1.06	1.03	1.02	1.01	1.01
Fixed	0.72	0.88	0.92	0.94	0.94	0.94	0.95
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.72	0.74	0.90	1.12	1.31	1.50	1.52
Battery							
Capital	*Div by 0*	1.95	1.30	1.19	1.14	1.16	1.13
Total	0.97	0.98	1.00	1.03	1.05	1.08	***1.09***

Hawai'i Results

Figure 18. Utilized installed capacity for Hawai'i Island Uncurtailable High DGPV case

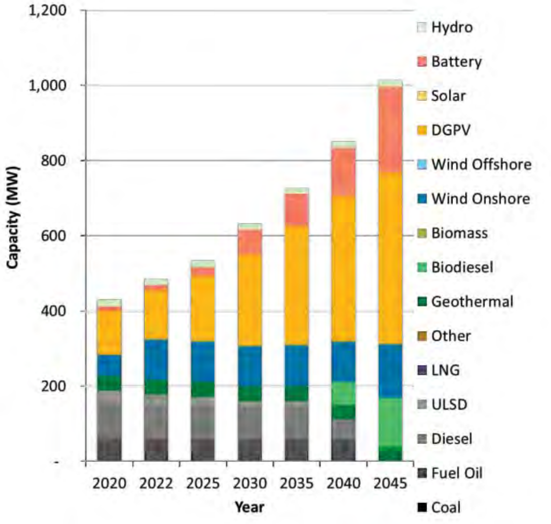

Table 18. Cumulative total resource cost for the Hawai'i No-LNG Uncurtailable High DGPV case (relative to Hawai'i No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.01	1.00	0.97	0.95	0.94	0.93
Fixed	1.01	1.00	1.00	1.01	1.01	1.01	0.75
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.02	1.20	1.43	1.61	1.76	1.90
Battery							
Capital	0.97	0.97	1.02	1.21	1.32	1.37	1.54
Total	1.00	1.01	1.04	1.08	1.13	1.18	***1.19***

6. Copperplate with Market DGPV Forecasts

The copperplate results show significant cost differences and build differences as compared to the individual island cases. There is a large increase in Hawai'i Island wind build, and a small increase in Maui solar, whereas the Oahu renewable build sees a large reduction. The thermal fleet capacity does not change significantly compared to the sum of the individual island cases, but in later years much of this thermal fleet is used for capacity with only the most efficient units across islands being dispatched for energy purposes.

The total cost saving across all islands is roughly $3 billion in present value 2016 dollars. This cost difference is an approximate upper bound value and more detailed scoping should be done to investigate both the engineering feasibility of building the cable and the engineering and siting feasibility of the large grid-scale renewable resource build, which RESOLVE assumes is the individual island base case result in absence of the Copperplate case.

Figure 19. Utilized installed capacity for Copperplate No-LNG Market DGPV case

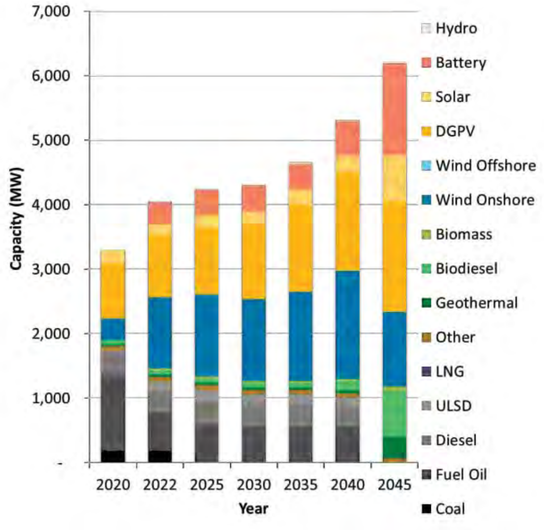

Table 19. Cumulative total resource cost for the Copperplate No-LNG Market DGPV case (relative to sum of individual island No-LNG Market DGPV case costs)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.78	0.80	0.81	0.81	0.80	0.80	0.80
Fixed	0.62	0.53	0.49	0.47	0.46	0.44	0.40
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.74	0.73	0.80	0.84	0.85	0.85	0.86
Battery							
Capital	0.00	0.85	0.84	0.84	0.84	0.85	0.85
Total	0.75	0.76	0.77	0.78	0.79	0.79	***0.79***

4: KEY STAKEHOLDER DEFINED CASES

Q14. PLEASE DESCRIBE THE STAKEHOLDER DEFINED INPUT ASSUMPTIONS USED TO DEFINE EACH CASE

A14. Key stakeholders defined six sensitivity cases for E3 to run through the RESOLVE model to compare against the results of the Company-defined cases. Each key stakeholder and the input assumptions used to alter the Company defined base cases are outlined below.

<u>1. Ulupono</u>: Increase all fuel costs by 35% above the base assumptions on all islands, to account for the hedging value provided by renewable resource against volatile future fuel prices. All other system assumptions were held constant.

<u>2. Hawaii Gas</u>: Hawaii Gas provided an alternate LNG fuel pricing structure from the one developed by the Companies. This sensitivity case only applies to O'ahu, as Hawaii Gas' proposal only includes delivery of LNG to O'ahu.

<u>3. Fripp/Ulupono/Blue Planet</u>: On behalf of Ulupono and Blue Planet, Dr. Fripp provided increased renewable technical potentials on O'ahu from resources of lower quality than the resources identified in NREL's study. Further, Dr. Fripp provided a methodology for adjusting the hourly output profiles that the Companies have provided to E3 to model more granular capacity factors of both higher and lower quality resources than the single category of shapes used in the NREL-sourced data.

<u>4. Paniolo</u>: Paniolo Power provided alternate capital cost information for onshore wind on Hawai'i Island. The capital cost forecasts for pumped-storage hydro was the same as provided by the Companies. The only differences in pumped-storage hydro characteristics captured in RESOLVE are:

1) fixed O&M costs ($28/kW-yr provided by Paniolo vs. $30/kW-yr provided by the Companies), and

2) higher roundtrip efficiency of 85% instead of the 80% provided by the Companies.

In this sensitivity case, E3 paired 30 MW of onshore wind with 30 MW of pumped-storage hydro. Because Paniolo did not provide an alternate hourly profile for its wind unit performance, E3 used the same hourly profiles provided by the Companies to model the paired Paniolo project.

Table 20. Paniolo PSH capital costs

Year	Capital Cost (2016 $/kW)
2020	$2,295
2022	$2,224
2025	$2,117
2030	$1,938
2035	$1,868
2040	$1,798
2045	$1,728

5. Consumer Advocate No LNG: The Consumer Advocate asked E3 to use RESOLVE to test the impact of not meeting the state's Renewable Portfolio Standard as part of its long-term plan, with the goal of estimating how different a least-cost portfolio might look from one that meets the state's clean energy goals.

To run this sensitivity, the RPS target in each study year was removed, such that RESOLVE could choose the least-cost portfolio to meet energy and capacity needs. Some minor input assumptions were also changed, such as allowing the AES coal plant on Oahu to continue beyond 2022.

5. Consumer Advocate LNG: Using similar input assumption as the Consumer Advocate No LNG case, E3 ran a case where the LNG fuel forecast was extended through 2045 to estimate how LNG would affect the least-cost portfolio.

6. DBEDT: DBEDT asked E3 to run a case in which the military power units on Oahu (MCBH and JBPHH) are not planned, but the model is given the option of procuring resources with similar cost and performance characteristics.

Q15. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE THIRD PARTY DEFINED CASES

A15. Capacity graphs and cost tables, as described in Q9 and Q10, show utilized installed capacities and the cost of the cases relative to the base cases as defined in Q9: No-LNG Market DGPV forecast cases.

1. Ulupono Fuel Hedge Cases

Ulupono fuel hedge case results in little difference as compared to the base case no-LNG. The model chooses to maximize renewable build during the first five-year period and is constrained more by transmission and operations than by economics. During the middle years, each island adds steadily more renewable capacity. The final build is very similar, the difference being that renewable sources are built a few years earlier. For example, on Oahu offshore wind sources are built in 2020 and 2022, whereas in the base case they are not built until later years.

From a renewable energy perspective, the fuel hedge cases show that considering the hedge value of renewables on each island further increases the amount of energy from variable resources above the fraction generated in the No-LNG base case. The effect is relatively small on Maui and the Big Island because renewables are already very competitive against thermal generation prior to the fuel price hedge on these islands. Sales from renewables increase significantly on Oahu, however, because of the lower quality/higher cost renewable resource options. The increase in fuel price in the hedge scenario improves the competitiveness of renewables such that it is economical to procure significantly above RPS levels.

In the cost tables below we show the fuel price hedge as an actual cost, making these scenarios appear to be substantially more costly than the base case. If the hedge is not used as an actual cost, but only as a planning assumption, then the thermal variable cost increases shown in the tables below would not exist (they would be actually lower than 1 because there is less fuel burn due to the higher renewable build) and this plan would only be slightly higher cost than the base case on Oahu and nearly close to the base case on the neighbor islands.

Table 21. Portion of annual electricity from RPS-eligible sources in Ulupono fuel hedge cases compared to Company cases.

Oahu	2020	2022	2025	2030	2035	2040	2045
LNG Base	33%	35%	37%	40%	41%	70%	100%
No-LNG Base	33%	37%	55%	65%	71%	75%	100%
No-LNG fuel hedge	43%	53%	74%	79%	81%	85%	100%
Maui	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
LNG Base	49%	61%	61%	63%	64%	70%	100%
No-LNG Base	54%	75%	74%	76%	77%	83%	100%
No-LNG fuel hedge	57%	77%	79%	81%	85%	87%	100%
Hawaii	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
LNG Base	63%	76%	78%	80%	79%	80%	100%
No-LNG Base	63%	82%	83%	85%	87%	88%	100%
No-LNG fuel hedge	71%	86%	87%	88%	90%	90%	100%

Oahu Results

Figure 20. Oahu No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

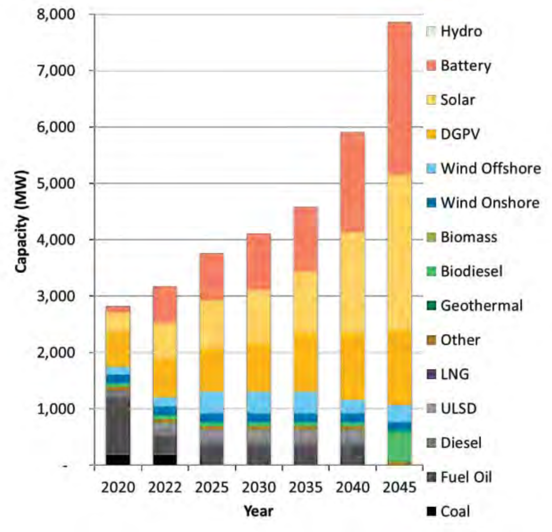

Table 22. Cumulative total resource cost for the Oahu No-LNG Market DGPV Ulupono fuel hedge case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.09	1.01	0.92	0.90	0.89	0.89	0.90
Fixed	0.86	0.80	0.76	0.74	0.73	0.72	0.75
Renewables							

Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	2.67	2.62	2.15	1.83	1.68	1.57	1.41
Battery							
Capital	*Div by 0*	2.04	1.91	1.86	1.77	1.76	1.50
Total	1.27	1.24	1.21	1.19	1.18	1.16	***1.14***

Maui Results

Figure 21. Maui No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

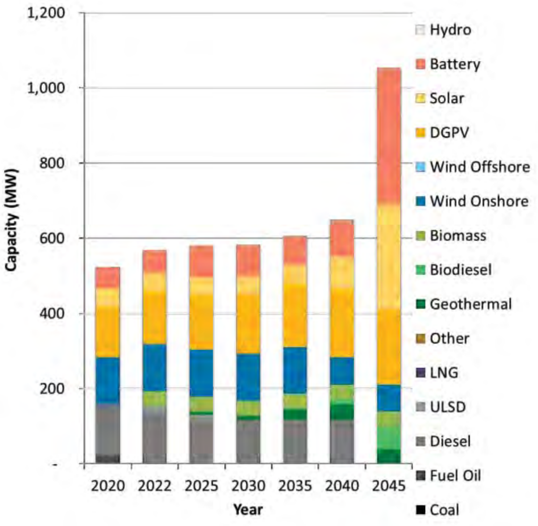

Table 23. Cumulative total resource cost for the Maui No-LNG Market DGPV Ulupono fuel hedge case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.36	1.31	1.26	1.22	1.18	1.18	1.17
Fixed	0.67	0.80	0.92	0.98	1.06	1.06	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.29	1.28	1.27	1.26	1.21	1.19	1.16
Battery							
Capital	*Div by 0*	4.84	2.28	1.88	1.63	1.58	1.40
Total	1.29	1.22	1.20	1.18	1.17	1.16	***1.14***

Hawai'i Island Results

Figure 22. Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

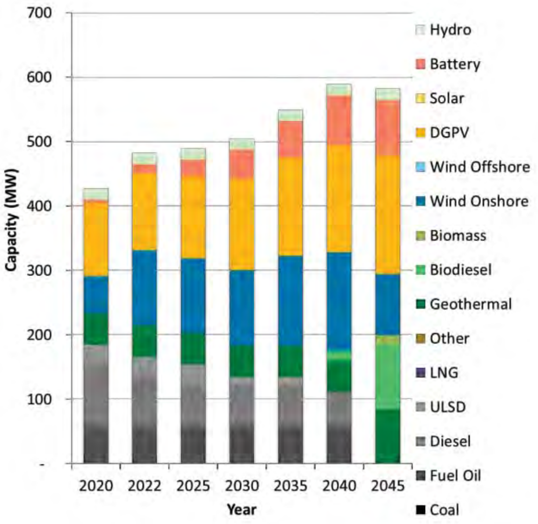

Table 24. Cumulative total resource cost for the Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.13	1.13	1.13	1.13	1.13	1.14	1.11
Fixed	1.78	1.78	1.78	1.79	1.79	1.80	1.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.98	0.98	0.98	0.99	0.98	0.93
Battery							
Capital	0.45	0.66	0.85	0.96	1.02	1.01	0.96
Total	1.19	1.19	1.19	1.19	1.19	1.18	***1.16***

2. Hawaii Gas Cases for Oahu

The Hawaii Gas case looks very similar to that of the base LNG case on Hawaii. The Hawaii Gas proposal is less expensive than the base LNG proposal on Oahu, but the actual difference is slightly smaller than the difference portrayed here, as the HECO LNG proposal gives Oahu responsibility for all hub import costs for all three islands as described above. The Hawaii Gas proposal results in LNG units being converted, but no new thermal resources being built during the early years. The renewable build is pushed to later years, but once again the final build in 2045 is similar to the base case build.

Oahu Results

Figure 23. Oahu Hawaii Gas LNG Market DGPV utilized capacity results

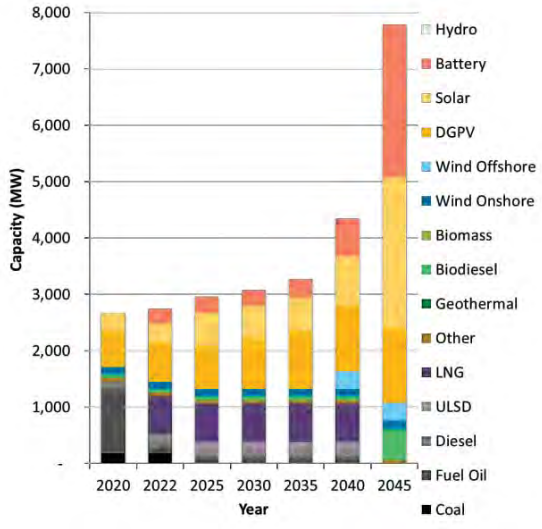

Table 25. Cumulative total resource cost for the Oahu Hawaii Gas LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.92	0.91	0.92	0.93	0.90	0.90
Fixed	1.00	1.44	1.73	1.89	1.97	2.02	1.92
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.90	0.70	0.61	0.58	0.63	0.74
Battery							
Capital	0.00	0.61	0.62	0.58	0.56	0.56	0.71
Total	1.00	0.95	0.91	0.88	0.85	0.85	***0.87***

3. Fripp/Ulupono/Blue Planet Enhanced Renewable Potentials on Oahu Cases

The main difference to note in the enhanced renewables potential case is the large increase in onshore wind capacity. The previous new onshore wind potential was only 30 MW (incremental to wind online by 2020), whereas now there are more than 2000 MW of potential capacity. The model does not build to the maximum onshore potential, but it does build close to 500 MW of new onshore wind resource. Once again, while these results are indicative of the kinds of renewable build Oahu might expect to build, we expect that the actual build will be contingent on the kinds of real world resources and costs which are received during an RFO.

Oahu Results

Figure 24. Enhanced renewable potential case No-LNG Market DGPV utilized capacity results

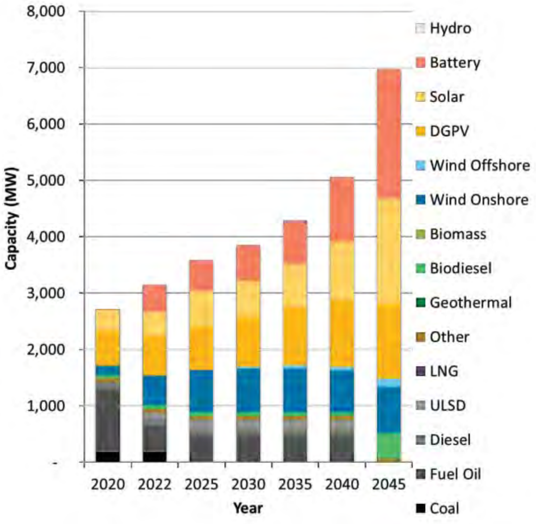

Table 26. Cumulative total resource cost for the Oahu Enhanced renewable potential No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	0.96	0.86	0.82	0.82	0.82	0.82	0.82
Fixed	0.97	0.93	0.90	0.88	0.87	0.87	0.83
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.22	1.71	1.49	1.33	1.25	1.20	1.13
Battery							
Capital	*Div by 0*	1.17	1.18	1.16	1.14	1.13	1.03
Total	0.99	0.99	0.98	0.98	0.97	0.97	***0.96***

4. Paniolo Wind + Pumped Storage on Hawai'i Island

The Paniolo wind and pumped-storage on Hawai'i Island case adds 30 MW of wind and 30 MW of pumped-storage hydro (PSH), with slight cost and performance changes to the base case assumptions. In this case, the combination of 30 MW of wind and 30 MW of PSH is added as a planned installation, that comes online in 2022, around which RESOLVE can optimize a least cost resource portfolio.

The results below show that the onshore wind build is very similar to the base case, with the 30 MW of Paniolo wind simply displacing 30 MW of other grid-scale onshore wind in the near-term. Compared to the base case, the 30 MW pumped-storage facility is much larger than the batteries built as a RESOLVE decision (14 MW by 2022). Further, PSH costs are higher than those of batteries, resulting in over 300% higher capital cost related to batteries* (which encompasses both batteries and Paniolo PSH in this case). On a total resource cost basis, the higher PSH cost results in a 13% increase relative to the base case under the normal operations considered by RESOLVE.

Hawai'i Island Results

Figure 25. Paniolo Wind + Pumped Storage case No-LNG Market DGPV utilized capacity results

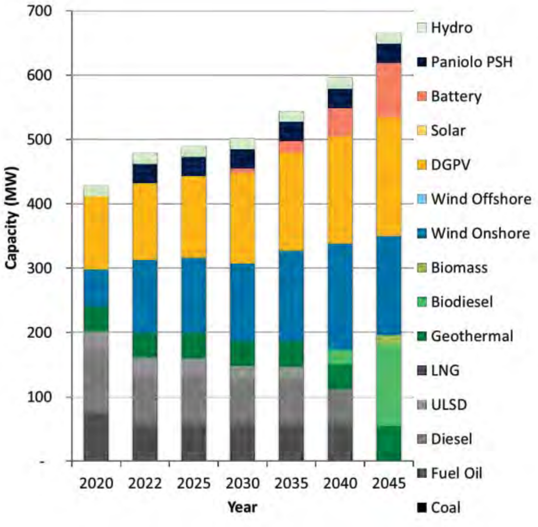

Table 27. Cumulative total resource cost for the Paniolo Wind + Pumped Storage case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.02	1.01	1.00	1.00	1.00	1.00	1.00
Fixed	1.19	1.09	1.05	1.04	1.04	1.03	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.05	1.02	1.04	1.05	1.05	1.05	1.05
Battery*							
Capital	0.00	2.86	3.82	3.72	3.72	3.59	3.37
Total	1.01	1.08	1.12	1.13	1.13	1.13	***1.13***

** Battery category includes pumped-storage hydro, which is a planned addition and not a RESOLVE decision*

5. Consumer Advocate No LNG No-RPS Constraint Cases

The Consumer Advocate no-RPS case results in a significantly different resource build on Oahu. The AES coal plant is kept online through 2045, which reduces the amount of other thermal usage as the price of coal remains below that of the liquid fuels. Furthermore, the thermal plants are used at a higher capacity factor than in the RPS constrained cases. There is still a significant amount of solar, batteries, and a smaller amount of offshore wind resources which are used because the renewable resources are cost competitive for energy, especially in later years of the plan. On Oahu, removing the RPS constraint leads to a case with total resource cost which is 87% of the RPS-constrained case.

On Maui and Hawai'i, however, the higher quality renewable resources are cost competitive with fuels such that the model chooses to build similar amounts of renewable sources, even in a non-RPS constrained world. The cost difference between the RPS-constrained and non-RPS-constrained cases is much smaller on these islands, with only a 1% difference on Maui and 2% difference on Hawai'i.

Oahu Results

Figure 26. Consumer Advocate Oahu No-RPS No-LNG Market DGPV utilized capacity results

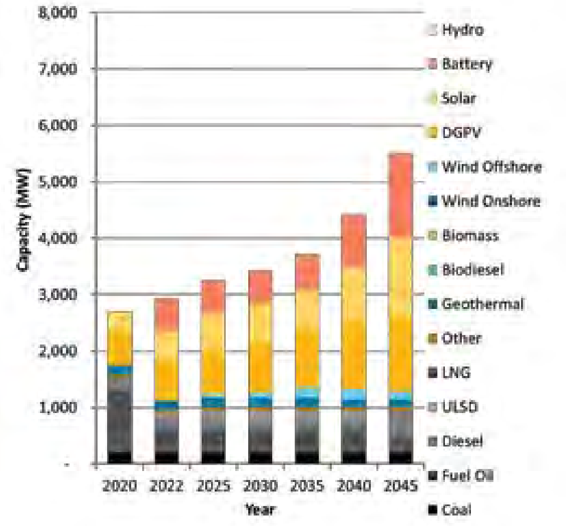

Table 28. Cumulative total resource cost for the Oahu No-RPS No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.97	0.89	0.87	0.86	0.86	0.94
Fixed	1.00	0.92	0.91	0.90	0.90	0.90	0.91
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.13	1.22	0.97	0.87	0.84	0.84	0.77
Battery							
Capital	0.00	1.38	1.33	1.25	1.18	1.13	0.94
Total	1.00	1.01	0.93	0.90	0.88	0.87	***0.87***

Maui Results

Figure 27. Consumer Advocate Maui No-RPS No-LNG Market DGPV utilized capacity results

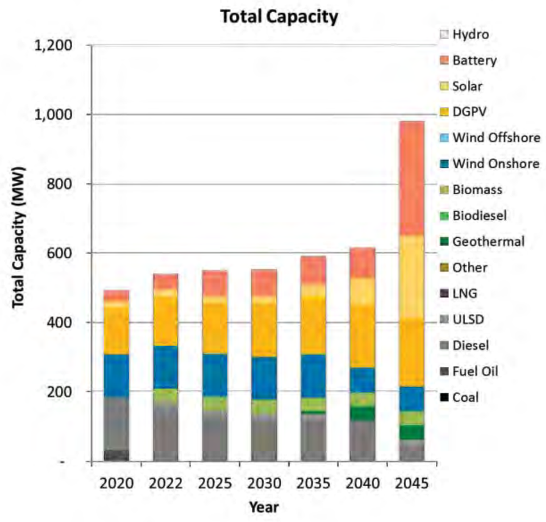

Table 29. Cumulative total resource cost for the Maui No-RPS No-LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fixed	0.64	0.82	0.89	0.91	0.94	0.95	0.96
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.96	0.96	0.97	0.97	0.96	0.96	0.96
Battery							
Capital	*Div by 0*	2.98	1.62	1.41	1.28	1.26	1.15
Total	0.97	0.98	0.99	0.99	0.99	0.99	***0.99***

Hawai'i Island Results

Figure 28. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV utilized capacity results

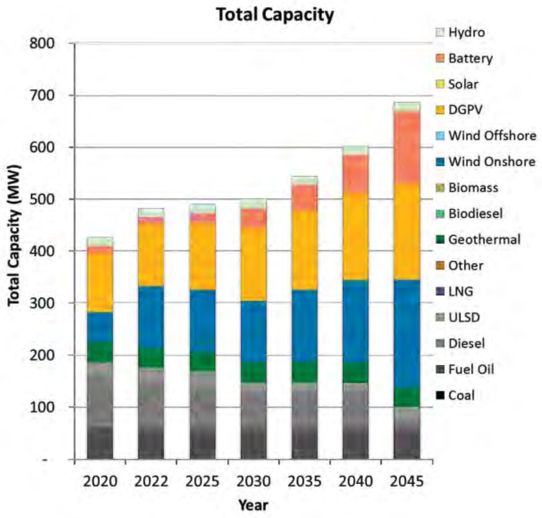

Table 30. Cumulative total resource cost for the Hawai'i Island No-RPS No-LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	1.08
Battery							
Capital	1.00	1.00	1.00	1.00	1.00	0.98	1.06
Total	1.00	1.00	1.00	1.00	1.00	1.00	***0.98***

6. Consumer Advocate LNG No-RPS Constraint Cases

In the Consumer Advocate LNG No-RPS Constraint case, we extend the LNG fuel price forecast through 2045 to allow thermal units that burn LNG to continue economic operation throughout the planning horizon.

Similar to the Consumer Advocate No LNG case above, the LNG case shows significantly different build on each island; however, more thermal plants stay online throughout the planning horizon on all islands due to the low fuel cost associated with LNG. Further, low cost LNG discourages significant grid-scale renewable buildout, which is most apparent with the reduction in grid-scale solar on Oahu and Maui in 2045. As noted in Table 3, while both Consumer Advocate No-RPS Constraint cases results in sub-100% RPS-eligible energy, the LNG case results in significantly lower energy from RPS-eligible resources on all islands. From a cost perspective, the LNG No-RPS Constraint case results in a 5-7 percentage point reduction below the Company No-LNG Market DGPV case.

Oahu Results

Figure 29. Consumer Advocate Oahu No-RPS No-LNG Market DGPV utilized capacity results

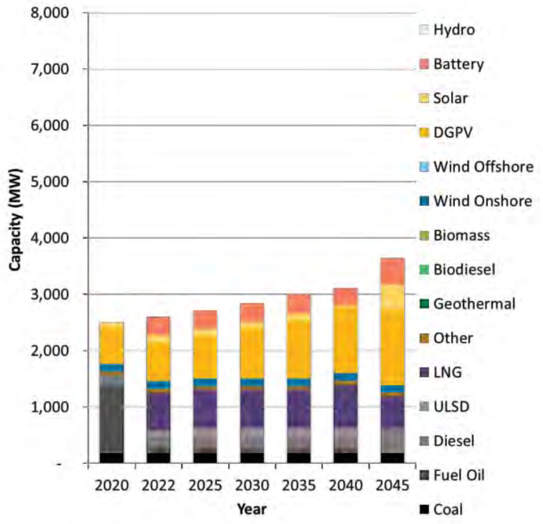

Table 31. Cumulative total resource cost for the Oahu No-RPS No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.09	0.88	0.76	0.72	0.70	0.69	0.74
Fixed	1.06	3.31	4.87	5.71	6.13	6.40	6.90
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.34	0.37	0.27	0.26	0.27	0.29	0.29
Battery							
Capital	0.00	0.76	0.74	0.69	0.65	0.60	0.45
Total	1.01	1.02	0.94	0.90	0.87	0.85	***0.84***

Maui Results

Figure 30. Consumer Advocate Maui No-RPS No-LNG Market DGPV utilized capacity results

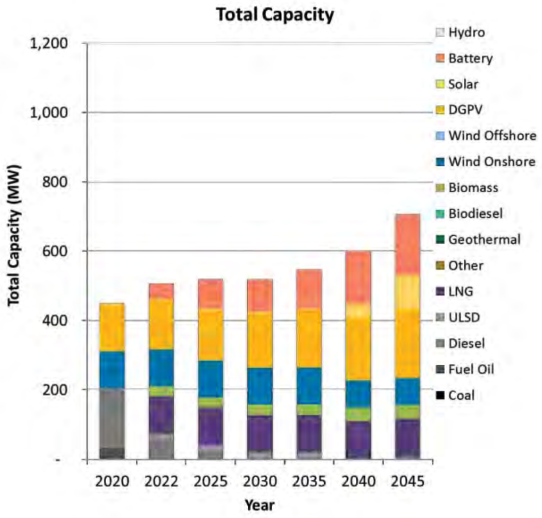

Table 32. Cumulative total resource cost for the Maui No-RPS No-LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.17	1.01	0.90	0.82	0.78	0.76	0.81
Fixed	0.80	0.92	0.97	0.97	0.96	0.90	0.83
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.51	0.53	0.55	0.57	0.58	0.61	0.60
Battery							
Capital	*Div by 0*	1.39	1.21	1.23	1.24	1.29	1.02
Total	0.99	0.92	0.88	0.85	0.83	0.81	***0.80***

Hawai'i Island Results

Figure 31. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV utilized capacity results

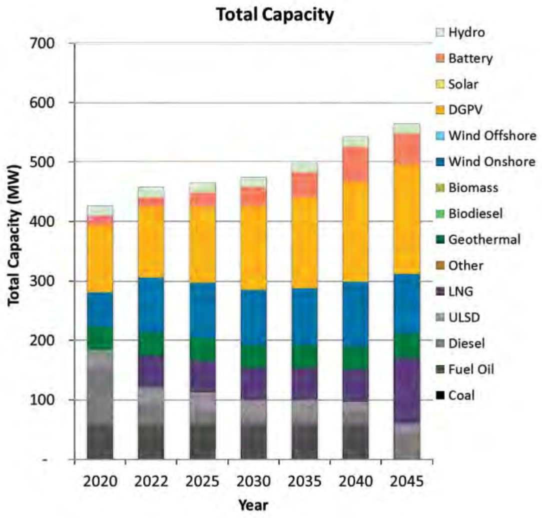

Table 33. Cumulative total resource cost for the Hawai'i Island No-RPS No-LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.90	0.82	0.76	0.73	0.71	0.75
Fixed	0.97	1.15	1.24	1.29	1.32	1.34	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.78	0.76	0.76	0.75	0.75	0.75
Battery							
Capital	1.19	1.19	1.18	1.09	1.04	1.00	0.87
Total	1.00	0.93	0.89	0.86	0.83	0.82	***0.81***

7. DBEDT No Military Units on Oahu

In the DBEDT no military unit case the Marine Corps Base Hawaii (MCBH) and Joint Base Pearl Harbor-Hickam (JBPHH) diesel power plants are not built. The model is given the option of procuring units with the same cost and performance characteristics, but RESOLVE chooses not to invest until 2045, when it procures biodiesel units with similar cost and performance characteristics to the military units. In the base case the Companies have assumed that the military units have planned fuel switching to biodiesel in 2045. RESOLVE optimizes to minimize costs by assuming normal operating conditions, with hourly reserve requirements specified by the Companies. However, RESOLVE does not capture the detailed transmission, power flow, and contingency constraints necessary to fully determine the need for new generation. These results act as a preliminary starting point based on planning level economics that will require further investigation by both parties and the Companies.

Oahu Results

Figure 32. DBEDT Oahu no military unit No-LNG Market DGPV utilized capacity

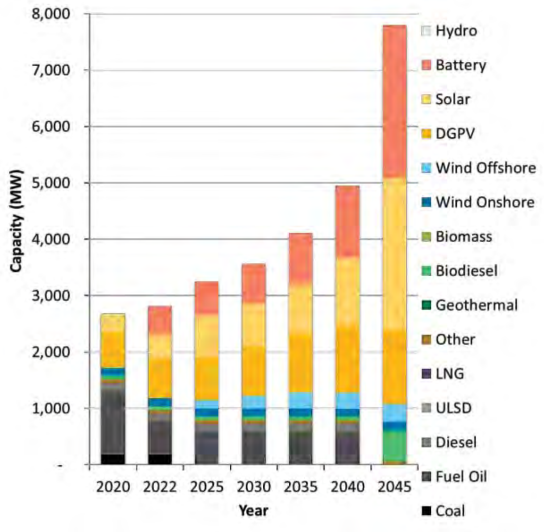

Table 34. Cumulative total resource cost for the DBEDT Oahu no military unit No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.99	0.98	0.99	0.99	0.99	0.99
Fixed	1.00	0.99	0.98	0.97	0.96	0.96	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.07	1.05	1.06	1.03	1.02	1.02	1.01
Battery							
Capital	0.00	1.19	1.24	1.24	1.23	1.23	1.15
Total	1.00	1.01	1.01	1.02	1.02	1.02	***1.02***

APPENDIX A: COMPANIES SENSITIVITY CASE DATA

The results shown in this appendix give the total MWs of each resource through 2045. Utilized capacity are resources that RESOLVE chooses to operate for least cost economic dispatch, and to meet system reserve needs. Unutilized capacity are defined in MWs that RESOLVE does not need to meet system constraints. These are candidate MWs for retirement, should the more detailed analysis conducted by the Companies show retirement is warranted.

No-LNG Market DGPV Installed Capacities

Oahu Results

Table 35. Oahu No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	534/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	119/-	237/-	314/-	314/-	312/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	446/-	763/-	763/-	829/-	1161/-	2693/-
Battery	-/-	426/-	456/-	571/-	747/-	1079/-	2714/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 36. Maui No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	163/38	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	3/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	61/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	139/-	139/-	139/-	139/-	139/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	28/-	77/-	259/-
Battery	-/-	34/-	75/-	75/-	85/-	87/-	346/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 37. Hawai'i Island No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	88/8	81/16	71/25	71/25	54/-	-/-
ULSD	30/-	30/-	30/-	19/11	19/11	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	31/-	118/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	22/-
Wind Onshore	58/-	119/-	119/-	119/-	140/-	161/-	140/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	21/-	38/-	50/-	82/-	109/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

No-LNG High DGPV Installed Capacities

Oahu Results

Table 38. Oahu No-LNG High DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	2022	2025	2030	2035	2040	2045
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	514/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	143/-	214/-	265/-	265/-	273/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	354/-	401/-	595/-	595/-	595/-	876/-	2052/-
Battery	-/-	426/-	455/-	620/-	788/-	1208/-	2733/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 39. Maui No-LNG High DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	2022	2025	2030	2035	2040	2045
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	165/36	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	37/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	126/-	126/-	126/-	126/-	126/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	-/-	32/-	75/-	75/-	89/-	121/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 40. Hawai'i Island No-LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	89/7	77/19	64/33	64/33	54/-	-/-
ULSD	30/-	30/-	30/-	5/25	5/25	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	20/-	110/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	109/-	109/-	109/-	109/-	108/-	139/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	25/-	66/-	86/-	131/-	205/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

LNG Market DGPV Installed Capacities

Oahu Results

Table 41. Oahu LNG Market DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	103/94	103/-	103/-	103/-	103/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	679/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	529/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	320/-	320/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	354/-	372/-	372/-	372/-	853/-	2654/-
Battery	-/-	257/-	357/-	357/-	424/-	619/-	2715/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 42. Maui LNG Market DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	81/14	33/62	-/84	-/95	-/95	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	61/-
Biomass	-/-	20/-	20/-	20/-	26/-	40/-	40/-
Wind Onshore	119/-	119/-	119/-	119/-	119/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	5/-	110/-	259/-
Battery	-/-	30/-	84/-	107/-	117/-	159/-	346/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 43. Hawai'i Island Market DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	32/11	24/19	12/31	12/31	-/-	-/-
ULSD	30/-	30/-	30/-	30/-	30/-	-/-	-/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	34/-	118/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	22/-
Wind Onshore	58/-	93/-	93/-	93/-	96/-	109/-	140/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	25/-	33/-	43/-	66/-	109/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

LNG High DGPV Installed Capacities

Oahu Results

Table 44. Oahu LNG High DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1173/114	103/94	103/-	29/74	29/74	29/74	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	679/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	502/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	297/-	297/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	227/-	227/-	227/-	227/-	227/-	410/-	1938/-
Battery	-/-	285/-	357/-	357/-	357/-	723/-	2736/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 45. Maui LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	85/10	33/62	-/84	-/95	-/95	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	20/-	20/-	20/-	20/-	40/-	40/-
Wind Onshore	110/-	110/-	110/-	110/-	110/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	-/-	26/-	84/-	110/-	125/-	161/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 46. Hawai'i Island LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	33/10	20/23	10/33	10/33	-/-	-/-
ULSD	30/-	30/-	30/-	8/22	6/24	-/-	-/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	17/-	110/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	73/-	73/-	73/-	73/-	53/-	139/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	29/-	58/-	70/-	101/-	205/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Uncurtailable DGPV Installed Capacities

Oahu Results

Table 47. Oahu Uncurtailable High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	526/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	57/-	190/-	190/-	190/-	250/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	354/-	512/-	689/-	689/-	788/-	999/-	2157/-
Battery	-/-	426/-	487/-	833/-	1205/-	1495/-	2790/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 48. Maui Uncurtailable High DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	162/38	162/38	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	37/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	120/-	120/-	120/-	120/-	120/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	17/-	34/-	75/-	75/-	89/-	121/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Results

Table 49. Hawai'i Uncurtailable High DGPV

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	89/7	88/9	88/9	88/9	54/-	-/-
ULSD	30/-	30/-	26/3	14/16	14/16	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	60/-	131/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	109/-	109/-	109/-	111/-	109/-	143/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	24/-	65/-	88/-	129/-	229/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Copperplate No-LNG Installed Capacities

Copperplate Results

Table 50. Copperplate capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1183/233	591/109	591/16	558/49	558/49	558/-	-/-
Diesel	345/82	345/82	345/82	345/71	345/82	302/82	-/-
ULSD	30/-	148/-	202/-	159/43	159/43	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	337/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	142/-	693/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	80/-
Wind Onshore	335/-	1099/-	1266/-	1266/-	1386/-	1672/-	1159/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	851/-	939/-	1017/-	1163/-	1334/-	1509/-	1688/-
Solar	203/-	203/-	203/-	203/-	245/-	272/-	739/-
Battery	-/-	324/-	406/-	406/-	406/-	539/-	1426/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

APPENDIX B: THIRD PARTY STAKEHOLDER SENSITIVITIES RESULTS

Ulupono Fuel Hedge Installed Capacities

Oahu Results

Table 51. Oahu No-LNG Market DGPV Ulupono fuel hedge capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1013/273	343/94	343/-	343/-	343/-	343/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	536/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	164/-	164/-	164/-	164/-	164/-	164/-
Wind Offshore	137/-	161/-	386/-	386/-	386/-	249/-	304/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	639/-	879/-	935/-	1120/-	1796/-	2758/-
Battery	117/-	650/-	830/-	1000/-	1139/-	1781/-	2720/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 52. Maui No-LNG Market DGPV Ulupono fuel hedge capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	23/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	136/65	135/65	118/82	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	13/6	-/18	-/18	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	7/-	10/-	28/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	13/-	59/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	125/-	125/-	125/-	125/-	125/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	50/-	50/-	50/-	50/-	50/-	88/-	282/-
Battery	56/-	61/-	83/-	83/-	79/-	97/-	363/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 53. Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	78/19	66/30	64/33	64/33	54/-	-/-
ULSD	30/-	30/-	30/-	13/16	13/16	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	48/-	48/-	48/-	48/-	48/-	48/-	85/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	15/-	100/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	14/-
Wind Onshore	58/-	117/-	117/-	118/-	140/-	153/-	95/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	6/-	15/-	26/-	47/-	57/-	78/-	87/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Hawaii Gas Installed Capacities

Oahu Results

Table 54. Hawaii Gas capacity results for Oahu

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	103/94	103/-	103/-	103/-	103/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	674/-	674/-	674/-	674/-	674/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	532/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	315/-	315/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	354/-	608/-	608/-	608/-	874/-	2679/-
Battery	-/-	262/-	282/-	282/-	327/-	674/-	2715/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Fripp/Ulupono/Blue Planet Enhanced Renewable Potential on Oahu Installed Capacities

Oahu Results

Table 55. Enhanced renewable potential case No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1114/173	469/94	469/-	469/-	469/-	469/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	444/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	533/-	763/-	782/-	782/-	752/-	818/-
Wind Offshore	-/-	-/-	-/-	27/-	61/-	62/-	156/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	384/-	444/-	653/-	653/-	772/-	1049/-	1883/-
Battery	7/-	486/-	544/-	642/-	781/-	1150/-	2286/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Paniolo Wind + Pumped Storage on Hawai'i Island Installed Capacities

Hawai'i Island Results

Table 56. Paniolo case No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	75/32	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	76/21	75/22	70/27	69/28	54/-	-/-
ULSD	30/-	27/3	27/3	20/9	20/9	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Paniolo PSH	-/-	30/-	30/-	30/-	30/-	30/-	30/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	23/-	125/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	16/-
Wind Onshore	58/-	114/-	118/-	121/-	142/-	165/-	154/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	-/-	-/-	-/-	8/-	18/-	45/-	85/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Consumer Advocate No LNG No-RPS Constraint Installed Capacities

Oahu Results

Table 57. Consumer Advocate Oahu No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	180/-	180/-	180/-	180/-	180/-
Fuel Oil	1135/151	421/94	421/-	421/-	421/-	421/-	319/-
Diesel	187/-	187/-	187/-	187/-	187/-	187/-	444/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	164/-	164/-	164/-	164/-	134/-	134/-
Wind Offshore	-/-	-/-	46/-	89/-	176/-	176/-	130/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	553/-	709/-	709/-	709/-	1002/-	1429/-
Battery	-/-	587/-	587/-	587/-	646/-	935/-	1497/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 58. Consumer Advocate Maui No-RPS No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	151/49	151/49	128/73	118/71	118/82	118/82	63/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	7/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	124/-	124/-	124/-	124/-	124/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	22/-	22/-	22/-	22/-	35/-	77/-	238/-
Battery	30/-	45/-	75/-	75/-	81/-	87/-	331/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 59. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	88/8	81/16	71/25	71/25	89/-	100/-
ULSD	30/-	30/-	30/-	19/11	19/11	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	119/-	119/-	119/-	140/-	160/-	208/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	21/-	38/-	50/-	75/-	141/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Consumer Advocate LNG No-RPS Constraint Installed Capacities

Oahu Results

Table 60. Consumer Advocate Oahu No-RPS No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	180/-	180/-	180/-	180/-	180/-
Fuel Oil	1196/91	106/91	103/-	103/-	103/-	103/-	-/-
Diesel	187/-	187/-	187/-	187/-	187/-	187/-	444/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	771/-	563/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	134/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	141/-	141/-	141/-	141/-	141/-	54/-	478/-
Battery	-/-	326/-	326/-	326/-	344/-	294/-	464/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 61. Consumer Advocate Maui No-RPS No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	0/-	0/-	0/-	0/-	0/-	0/-	0/-
Fuel Oil	32/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	173/28	55/40	23/72	2/82	2/93	2/93	9/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	108/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	30/-	30/-	30/-	30/-	40/-	40/-
Wind Onshore	105/-	105/-	105/-	105/-	105/-	78/-	78/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	5/-	39/-	99/-
Battery	1/-	46/-	84/-	96/-	112/-	156/-	177/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 62. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	32/11	24/19	12/31	12/31	22/-	43/-
ULSD	30/-	30/-	30/-	30/-	30/-	17/-	17/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	113/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	93/-	93/-	93/-	96/-	110/-	102/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	25/-	33/-	43/-	61/-	52/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

DBEDT No Military Units on Oahu Installed Capacities

Oahu Results

Table 63. DBEDT Oahu No Military Unit No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1137/150	598/94	598/-	598/-	598/-	598/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	-/-	-/-	-/-	-/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	534/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	149/-	149/-	149/-	149/-	149/-	134/-	164/-
Wind Offshore	-/-	-/-	140/-	226/-	286/-	286/-	312/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	446/-	764/-	764/-	898/-	1229/-	2693/-
Battery	-/-	506/-	592/-	701/-	908/-	1279/-	2714/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

APPENDIX C: PRM METHODOLOGY USED IN RESOLVE

Planning reserve margin (PRM) is designed to ensure that enough dependable generation capacity is available to meet expected demand in the planning horizon. It is defined as the differences between the resources available and the expected peak period loads. Under conventional conditions, a system planner can calculate expected peak load and ensure there are enough reliable dispatchable resources available to meet the expected peak load plus some margin for reserves, contingencies, planned maintenance, and unplanned events. Typically this process involves choosing a reliability standard based on an expected loss of load probability LOLP (e.g., 1 day in 10 years), and a corresponding PRM designed to maintain that LOLP over the planning horizon in each plan. However, for jurisdictions that are increasing their dependence on renewable or Variable Energy Resources (VERs) to meet their RPS requirements, the simple PRM calculation above needs to account for the specific VERs contributions to PRM at each stage in the plan.

Because VERs produce energy that is stochastic by nature, it is unreasonable to count their entire nameplate capacity in calculating the amount of resources available to meet PRM (i.e., a 20MW wind plant should not contribute 20MW to the PRM). Conversely, completely ignoring the renewable resources in the PRM calculation would result in an excessive thermal build that is unused for large amounts of time because of expensive fuel costs or RPS constraints. The RESOLVE methodology creates a simple metric representing the amount of capacity a planner can rely on to attribute to renewable resources in maintaining "dependable capacity."

Unlike a traditional PRM calculation which is focused on maintaining sufficient capacity to serve the expected peak load, the PRM methodology outlined below is calculated for every hour in the planning horizon. While only one of these hours is binding, we cannot identify that hour because it is determined by an interplay of energy demand, demand response, DGPV, and the "dependable capacity" produced for each renewable resource. For example, the binding hour for PRM in a system with only solar renewable resources will likely occur in the evening, and the binding hour for a system with a combination of wind and solar resources could easily occur much earlier in the day. Below, we describe the methodology used to value the PRM contribution of renewable resources in this planning study that incorporates that interplay.

We begin with normalized hourly generation shapes for each renewable resource. In this case, the normalized hourly generation shapes were produced by the National Renewable Energy Laboratory and are hourly forecasted generation for 2045.

CALCULATION STEPS:

1. Calculate the distribution of the hourly renewable output for each renewable resource for each season-hour (e.g., summer hours 1-24).
2. Calculate the 10th percentile of each distribution above (10th percentile to represent the energy a planner can rely on for the identified renewable resource to provide with a 90% confidence level).
3. Use the identified 10th percentile calculated for each renewable resource in each season-hour and map it to the entire year (e.g., apply the 10th percentile value for Summer Hr 12 to the 12th hour of all summer days in the year in question in the plan on each island).
4. For each renewable resource, multiply the hourly 10th percentile values calculated above in Step 3 by the installed nameplate capacity of the renewable resource to calculate the hourly "dependable capacity" MW contribution of that renewable resource to the PRM.
    a. For example: assume the 10th percentile for solar Summer Hr 12 was 0.10, and the system had 110MW of nameplate solar installed. Then, the solar contribution to PRM during each Summer Hr 12 would be 0.10*110MW = 11MW.
5. For each hour, add together the PRM contributions from renewable resources, thermal resources, and batteries (thermal and battery contributions described below) to calculate the hourly PRM generation available.
6. Compare the available PRM generation with the PRM requirement, which is specified as a multiplier (greater than 1) of the hourly load.
7. If the generation side of the PRM constraint is greater than the load side for all hours, the PRM requirement has been met for the year in question. If there are one or more hours in which the PRM load requirement is greater than the generation resources available to meet PRM, the model must procure additional generation resources at least cost.

In this way, RESOLVE can rely on some level of renewable output for capacity instead of relying solely on an increasingly lower capacity factor thermal fleet in a high RPS world.

THERMAL AND BATTERY CONTRIBUTION TO PRM

Thermal resources contribute their maximum rated power output towards the PRM constraint.

In this planning study, we find that batteries are built more for energy purposes (i.e., absorbing high renewable output hours and shifting the energy to lower output hours) than for providing capacity. Nevertheless, we allow batteries to contribute to PRM. A battery's contribution to the PRM constraint is the power output a battery could discharge for 4 hours. For example, if a battery held 4kWh of energy in its pack, then its contribution to PRM would be 1kW as that is the power output the battery could maintain for 4 hours. This 4-hour cutoff is consistent with planning methodology used in the California market, which is one of the few markets with explicit formulations for how to evaluate the planning and capacity contributions of batteries.

Suitability of using a simple single hour and fixed PRM Number

The methodology described above is relatively simple and designed to determine the economic comparison of costs and benefits of a large number of cases over a relatively short period. It is largely unbiased towards different resources and is therefore suitable for comparing the costs of each plan.

Although the proposed process accounts for a VERs contribution to meeting a simple single PRM calculation for a single hour, the approach is too simple to assure that the reliability between each plan or over the course of each plan is maintained. For this reason, the companies have proposed using a number of other models to test the reliability of each of the studied plans; however, even that analysis is probably insufficient and limited by time, data and analytical tools. In particular, the simple single hour contribution of each VER and the fixed PRM percentage over the course of the expansion plan are simplifications that need to be tested.

In California, as part of their long term planning process, we are currently building a version of RESOLVE that incorporates information from our RECAP model that determines the amount specific LOLP and PRM needed for each plan over time and the Equivalent Load Carrying Capability (ELCC) of each VER over time in each plan as a more accurate way to counting VERs in their contribution to dependable capacity. A description of how RESOLVE is being adapted to incorporate a more detailed check on reliability in California can be found here:

http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451565

ASCEND ANALYTICS: ASCEND OPTIMAL RESOURCE ANALYSIS

ASCEND OPTIMAL RESOURCE ANALYSIS

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December 16, 2016

Contents

Executive Summary

Ascend Analytics ("Ascend") of Boulder, Colorado, was selected by Hawaiian Electric Companies ("the Companies") to perform modeling analysis on the Post-April PSIP Plans developed in the Companies' December 2016 PSIP filing. Ascend performed modeling analysis using its PowerSimm software.

Ascend performed validation of resource plans developed by the Companies and the Companies' consultant Energy and Environmental Economics (E3). The following plans were validated by Ascend's PowerSimm software:

Oahu (OAHU)
Post-April PSIP Plan
E3 Plan – Least cost resource plan without LNG
E3 Plan with LNG – least cost resource plan with LNG
Hawaii (HELCO)
Post-April PSIP Plan developed by the Companies
E3 Plan – least cost resource plan without LNG
Maui (MECO)
Post-April PSIP Plan developed by the Companies
E3 Plan – least cost resource plan without LNG

Table 1: Summary of the plans developed by the Companies and E3, which Ascend evaluated through Powersimm.

PowerSimm's evaluation of the Post-April PSIP Plans and E3 Plans align with the general trends found in Companies' evaluation of these plans through their Plexos model. As in the Plexos evaluations, PowerSimm found there to be only a marginal difference between the Oahu E3 Plan and the Oahu Post-April PSIP Plan, while calculating a significant reduction in costs for the Oahu E3 Plan with LNG relative to the Post-April PSIP Plan. For the Maui E3 Plan, PowerSimm calculated an 8% reduction in costs when compared with the Maui Post-April PSIP Plan, while Plexos results show an 7% reduction. For Hawaii, PowerSimm calculated a 2% reduction in total costs, and Plexos calculated a 9% reduction in total costs.

Ascend also utilized PowerSimm to evaluate the merits of adding flexible thermal units to Oahu's thermal fleet. With Oahu's high renewable penetration rates, thermal generation's role shifts from meeting base load to complementing the increasing levels of intermittent renewable generation. Since wind and solar generation cannot be regulated to meet changes in load, thermal generation becomes a key asset in addressing the imbalances that arise between supply and load in a system with such variable outputs. To respond to these imbalances, thermal units have to be flexible, ramping up, ramping down, starting up and shutting off much more frequently than in the past. PowerSimm determined the optimal introduction of flexible thermal unit additions to Oahu's preexisting thermal fleet. Ascend then compared Oahu's forecasted costs with (1) its existing fleet, (2) the Post-April PSIP Plan's updated fleet, and (3) the updated fleet developed by Ascend. The results show that the addition of flexible thermal units to the preexisting fleet can provide significant savings.

In addition to validating the Post-April PSIP Plans and E3 Plans, Ascend has further optimized the Post-April PSIP Plans by utilizing PowerSimm software to systematically incorporate uncertainty into the planning process. By rigorously simulating the impact of weather on renewables and load, PowerSimm determined the need for substantial additions of batteries that can respond to the natural variability of high renewable penetration rates. Ascend has determined the economic and operational merit of adding a substantial volume of energy storage by 2045. PowerSimm also incorporated uncertainty in fuel prices that helped determine the economic merit of increased expansion of renewable generation in excess of the RPS standards. For example, the optimal mix of renewables for Oahu includes a 57% increase in forecasted utility solar introductions, a 21% increase in forecasted offshore wind introductions, and an optimized battery buildout plan that reaches 10,000 MWh by 2045. The results of PowerSimm's optimization of renewables and batteries for Oahu are presented below in Figure 1.

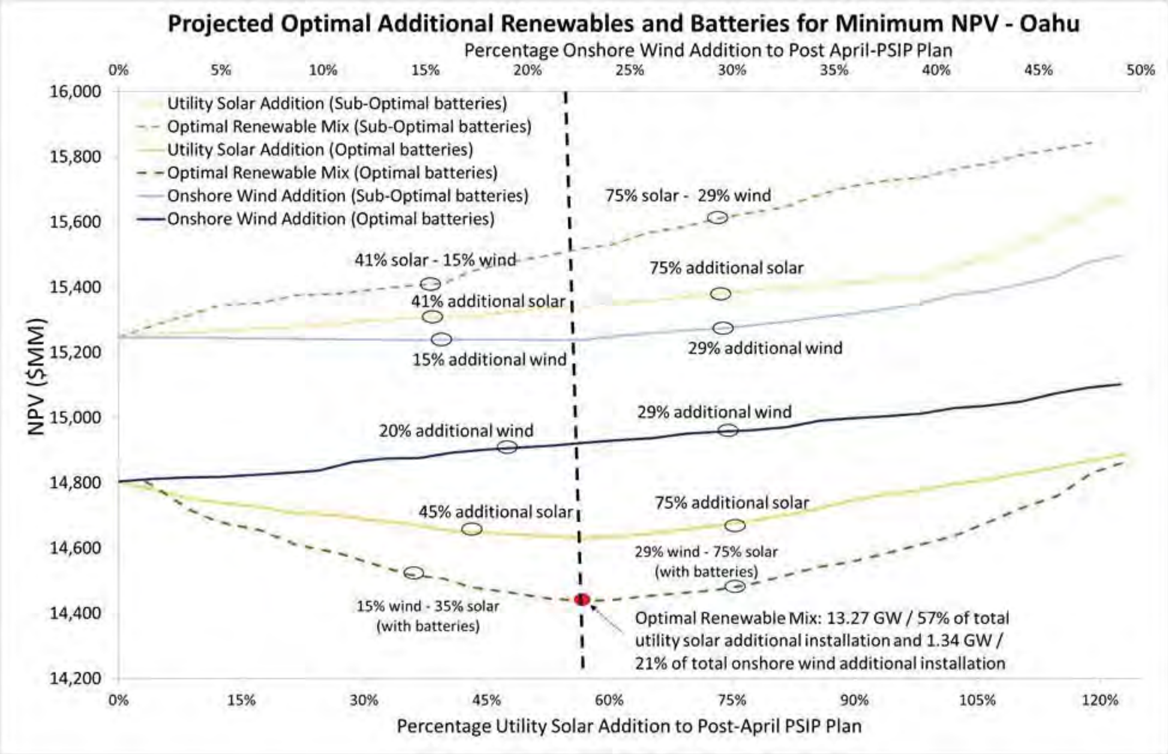

Figure 1: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Oahu's portfolio.

Ascend also optimized the Post-April PSIP Plans for Maui and Hawaii. The optimal resource mix for Maui includes a 74% increase in utility solar, a 34% increase in onshore wind, and the addition of 2,400 MWh batteries. The optimal resource mix for Hawaii includes an 87% increase in forecasted onshore wind introductions, and an optimized battery buildout plan that reaches 180 MWh by 2045.

For each of the islands, Ascend compares the net present value (NPV) of total portfolio costs from the present to 2045 for the original Post-April PSIP Plan, the two E3 Plans, as well as two Ascend-developed Plans. The two Ascend-developed plans are: 1) Ascend's optimization of the Post-April PSIP Plan with batteries (the Post-April PSIP Plan with Batteries), 2) Ascend's optimization of the Post-April PSIP Plan with renewables and batteries (the Ascend Plan). Relative to the original Post-April PSIP Plans, the Post-April PSIP Plans with Batteries provide a 1%-3% reduction in NPV portfolio costs for the Companies, while the Ascend Plans provide a slightly larger reduction of 3-5% in NPV portfolio costs for the Companies.

PowerSimm also analyzed resource adequacy under conditions of increasing intermittent renewable penetration. PowerSimm's analysis demonstrates that while intermittent renewables combined with batteries reduce the Companies' need for thermal generation, they do not nullify this need. Utilizing its ability to capture a wide range of possible future conditions, PowerSimm shows that a significant level of thermal generation capacity will still be necessary to reliably meet load by 2045, when the Companies' resource mix will be 100% renewable. Since there is always a possibility for extreme weather scenarios that severely reduce solar and wind generation, the Companies' thermal fleet has to have sufficient capacity to make up for substantial losses in intermittent renewable generation in order to ensure future resource adequacy. Ascend assessed the Loss of Load Probability (LOLP), or the probability of outages due to load exceeding supply, for the plans. The results indicate that the Oahu E3 Plan and the Maui E3 Plan would not be able to maintain the security of the energy supply, leading to higher chances of power outages. Both the Oahu and Maui E3 Plans accelerate the retirement of thermal generators without providing sufficient updates to the thermal fleet. These results suggest that upgradations of the thermal fleet would be an essential component of a viable integrated resource plan.

The analysis of all the plans and their optimized derivations was conducted on an hourly scale. To gain more insight into the sub-hourly dynamics of the Companies' power systems under conditions of higher renewable penetration, Ascend utilized PowerSimm's System Flexibility Software. System Flexibility Software uses historical renewable generation data to evaluate at the minutely level the Companies' flexible generation requirements (i.e. minutely, sub-hourly and hourly ramps and cycles) that accompany the integration of intermittent renewables. The results demonstrate that flexible generation requirements increase dramatically with the increasing levels of intermittent renewable generation, particularly with increasing solar. Batteries provide an excellent option for balancing out these sub-hourly and hourly fluctuations because of their ability to discharge energy precisely and extremely rapidly, with no additional production costs.

Ascend compared the costs of meeting these flexible generation requirements with batteries versus with conventional thermal generation. For this section, PowerSimm evaluates batteries that charge and discharge on an hourly scale (flexible batteries) and minutely scale (regulation batteries). Importantly, regulation batteries are not included in the optimized plans, which were developed and evaluated on an hourly-scale. The results support an introduction into Oahu's system of flexibility batteries by 2022 and an immediate introduction of regulation batteries. The savings provided by these two types of battery grow over time with the higher renewable penetration rates.

In sum, through the analysis of the given resource plans and the development of the Ascend-optimized resource plans, this report provides insight into: (1) the benefits of flexible thermal generation with higher renewable penetration, (2) the benefits of load-shifting batteries with higher renewable penetration, (3) the necessity for substantial dispatchable generation in order to maintain resource adequacy in a system with higher levels of intermittent renewables, and (4) the benefits of serving regulation with batteries instead of with conventional thermal generation in a system with higher levels of intermittent renewables.

1. Background

Following their April 2016 Power Supply Improvement Plan (PSIP) filing, Hawaiian Electric Companies ("the Companies") selected Ascend Analytics ("Ascend") of Boulder, Colorado, to perform modeling analysis on the plans developed for the December PSIP filing using Ascend's PowerSimm suite of products. PowerSimm is an analytics platform that systematically incorporates uncertainty into resource selection and capacity expansion planning.

This report's objective is to evaluate the Companies' Post-April PSIP Plans and E3's optimization of these plans, as well as to optimize the original Post-April PSIP Plans through the utilization of Ascend's PowerSimm model. In this report, Ascend will first provide PowerSimm's evaluation of the Post-April PSIP Plans and E3 plans for each island system. Second, this report will go over the benefits of flexible thermal generation for Oahu, presenting the optimal introduction of flexible thermal units into Oahu's thermal fleet. Third, this report will present PowerSimm's analysis on resource adequacy for the plans, highlighting the need to maintain sufficient dispatchable generation capacity to ensure the security of supply under all weather conditions. Fourth, this report will present the details on the resource plans created by Ascend for each of the three island systems, comparing them to the non-Ascend resource plans discussed earlier in the report. Fifth, this report will detail the sub-hourly and hourly flexible generation requirements that accompany high levels of intermittent renewable penetration, and additionally show the benefits of utilizing batteries to address these flexible generation requirements.

For each of the three island systems, Ascend analyzes and compares four plans, two that were not developed by Ascend, and two that were developed by Ascend. For Oahu, Ascend evaluates an additional non-Ascend Plan. The plans not created by Ascend (i.e., the original Post-April PSIP Plan, the E3 Plan and the E3 Plan with LNG) will be reviewed in Section 2. The two plans developed by Ascend (i.e., the Post April PSIP Plan optimized with batteries, and the Post-April PSIP Plan optimized with both renewables and batteries) will reviewed in Section 4, and then compared to the three other plans. A summary of all the plans included in this report are provided in Table 2 below.

	Name	Brief Description
Non-Ascend resource plans evaluated by Ascend (Detailed in Section 2)	Post-April PSIP Plan	Post-April PSIP Plan without modification
	E3 Plan[1]	Post-April PSIP plan optimized through E3's RESOLVE model; no LNG
	E3 Plan with LNG (only for Oahu)	Post-April PSIP plan optimized through E3's RESOLVE model; with LNG
Ascend-developed resource plans (Detailed and compared with non-Ascend plans in Section 4)	Post-April PSIP Plan with Batteries[2]	Original Post-April PSIP plan with an Ascend-optimized battery buildout plan
	Ascend Plan	Post-April PSIP plan with optimized levels of utility PV and offshore wind, and optimal battery buildout plan

Table 2: Plans included in this report.

Importantly, the Post-April PSIP Plans have slightly different assumptions in Section 2 and Section 4. As opposed to its "High" DGPV assumptions in the initial comparison with the E3 Plans in Section 2, the Post-

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[1] In addition to the two plans, Ascend also evaluates the E3 Plan with LNG for Oahu.

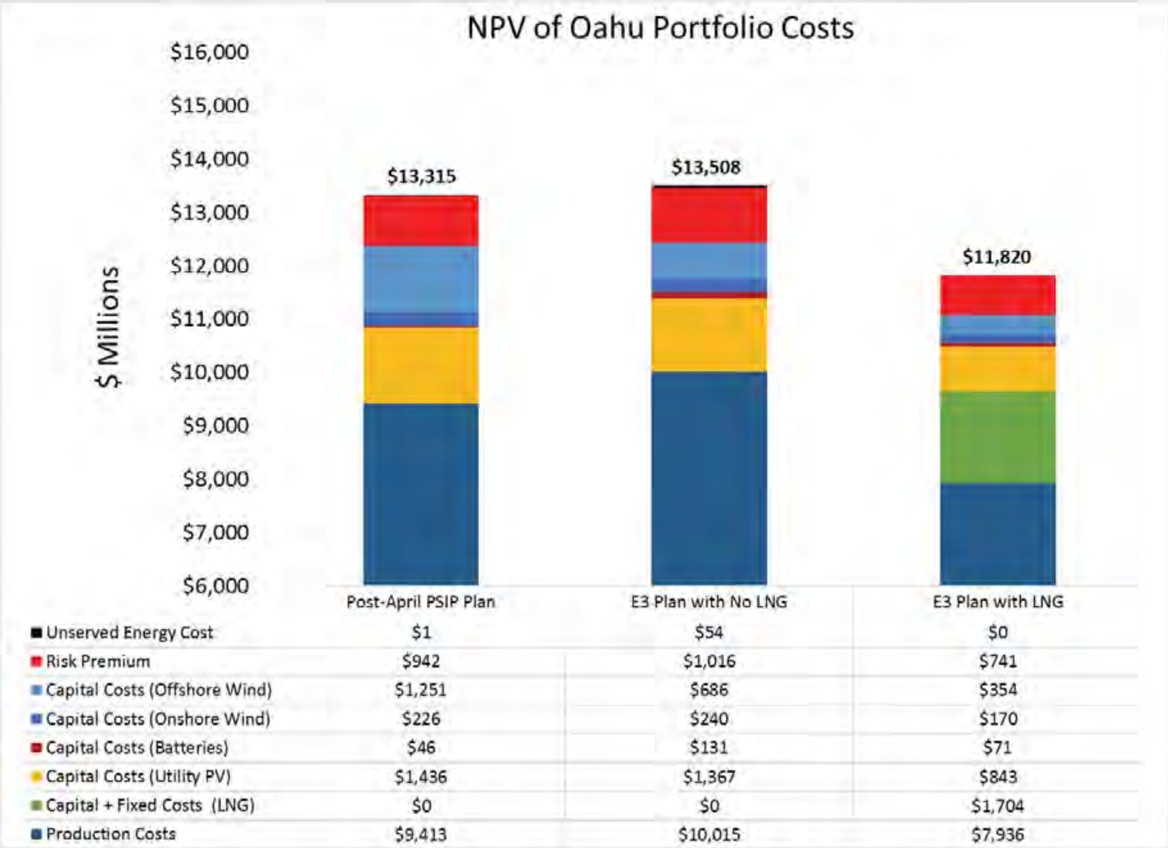
[2] It is worth noting that the original Post-April PSIP Plans do include batteries, but at sub-optimal levels. Ascend uses the naming convention 'Post April Plan with Batteries' for the sake of expediency.

April PSIP Plans in Section 4 contain lower, "Market" DGPV assumptions in the comparison with the Ascend-developed plans, which also use the Market DGPV assumptions. The E3 Plans evaluated in Section 2 and Section 4 are identical, containing High DGPV assumptions.

Additionally, the costs of the plans are calculated in a slightly different manner in Section 2 and Section 4. In Section 2 the total costs of the plans are calculated without DGPV costs, while in Section 4 they are calculated with DGPV costs included.

2. Validation of Post-April PSIP Plans and E3 Plans

Ascend used PowerSimm to evaluate the total net present value (NPV) of portfolio costs for the Post-April PSIP Plan and the E3 Plan with no LNG for each island system. Additionally, PowerSimm analyzed the NPV Portfolio costs of the Oahu E3 Plan with LNG.



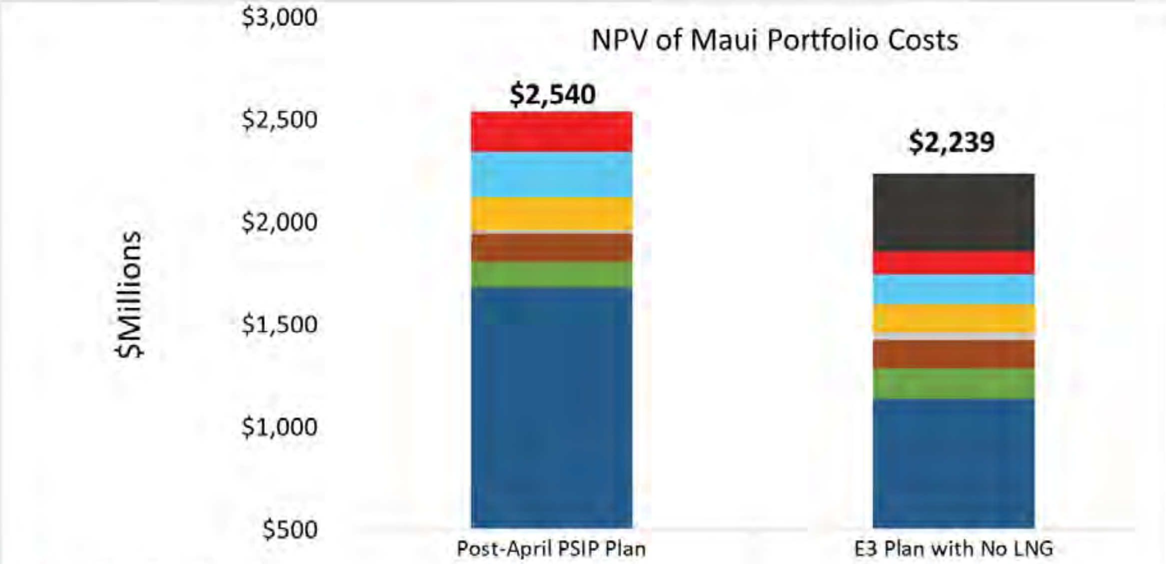
	Post-April PSIP Plan	E3 Plan with No LNG	E3 Plan with LNG
■ Unserved Energy Cost	$1	$54	$0
🟥 Risk Premium	$942	$1,016	$741
🟦 Capital Costs (Offshore Wind)	$1,251	$686	$354
🟦 Capital Costs (Onshore Wind)	$226	$240	$170
🟥 Capital Costs (Batteries)	$46	$131	$71
🟨 Capital Costs (Utility PV)	$1,436	$1,367	$843
🟩 Capital + Fixed Costs (LNG)	$0	$0	$1,704
🟦 Production Costs	$9,413	$10,015	$7,936

Figure 2: NPV Portfolio Costs for the Oahu Post-April PSIP Plan and E3 Plans.

According to PowerSimm's results, the E3 Plan has an NPV Portfolio cost that is $193 M higher than the original Post-April PSIP Plan. The E3 Plan installs less renewable capacity than the Post-April PSIP Plan. In particular, the offshore wind capital costs for the E3 Plan is 45% less than the offshore wind capital costs for the Post April-PSIP Plan. Thus more thermal generation must be utilized in the E3 plan, causing the E3 plan to have $602 M more in production costs than the Post-April PSIP Plan.

PowerSimm incorporates into its evaluation of NPV portfolio costs penalties for a resource plan's expected shortfalls in meeting load under the Unserved Energy Cost category. For each MWh short, PowerSimm provides a penalty of $10,000. Since the Oahu E3 Plan falls short in meeting resource adequacy standards, its portfolio costs rise by $50 M with the inclusion of these penalties. The results of PowerSimm's analysis of resource adequacy for the Oahu plans are discussed in section 4.3.1.

Compared to the original Post-April PSIP Plan, the E3 Plan reduces portfolio costs by 11%, or $1,495 M. The lower fuel prices of LNG are the chief contributor to the lower NPV costs. LNG conversion reduces total production costs by $1,477 dollars. Additionally, since LNG fuel prices are less volatile, the risk premium, which monetizes the risk of fuel exceeding the mean of its forecasted price, decreases significantly for the E3 Plan with LNG.

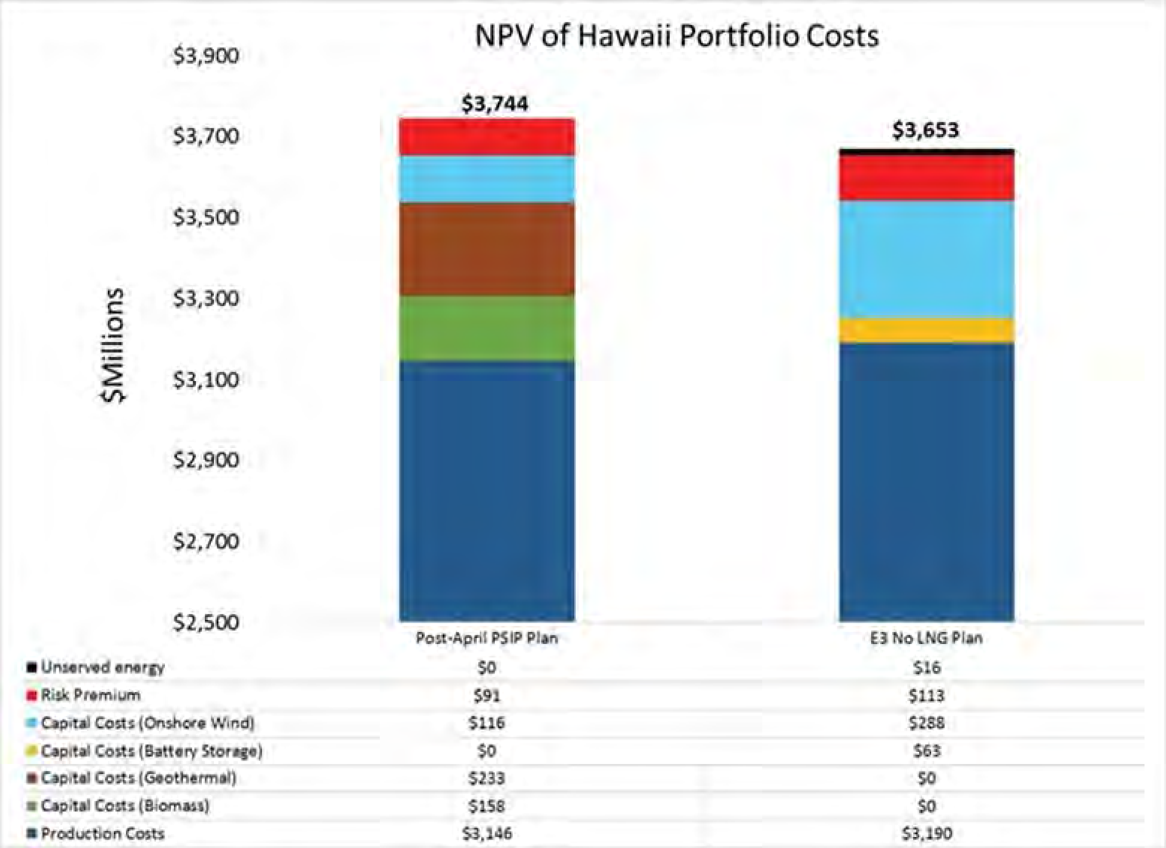


	Post-April PSIP Plan	E3 Plan with No LNG
■ Unserved Energy Cost	$0	$382
🟥 Risk Premium	$199	$113
🟦 Capital Costs (Onshore Wind)	$217	$146
🟨 Capital Costs (Utility Solar)	$162	$139
⬜ Capital Costs (Battery Storage)	$15	$37
🟫 Capital Costs (Geothermal)	$141	$134
🟩 Capital Costs (Biomass)	$124	$152
🟦 Production Costs	$1,683	$1,138

Figure 3: NPV Portfolio costs of the Maui Post-April PSIP Plan and E3 Plan.

Relative to the Maui Post-April PSIP Plan, the Maui E3 Plan reduces portfolio costs by $301 M. For intermittent renewables, the E3 Plan's capital costs are $94 M less than the Post April PSIP Plans' capital costs. Even more striking is the reduction of $545 M in production costs provided by the E3 Plan. However, the Maui E3 Plan fails to meet resource adequacy standards to an even greater degree than the Oahu E3

Plan, which adds $382 M to its portfolio costs. PowerSimm's analysis of resource adequacy for the Maui E3 Plan will be discussed in section 4.3.2.



	Post-April PSIP Plan	E3 No LNG Plan
■ Unserved energy	$0	$16
■ Risk Premium	$91	$113
■ Capital Costs (Onshore Wind)	$116	$288
■ Capital Costs (Battery Storage)	$0	$63
■ Capital Costs (Geothermal)	$233	$0
■ Capital Costs (Biomass)	$158	$0
■ Production Costs	$3,146	$3,190

Figure 4: NPV Portfolio Costs the Hawaii Post-April PSIP Plan and E3 Plan.

Compared to the Hawaii Post-April PSIP Plan, the Hawaii E3 Plan lowers NPV Portfolio costs by $91 M.

Though Ascend's evaluation through PowerSimm and the Companies' evaluation through Plexos differ in their forecasted costs for the plans, the general trends of the results from the two models show a relative consistency. The table below shows the percent difference in total costs for each E3 Plan relative to the base Post-April PSIP Plan according to the two models.

Percent difference in costs of E3 Plan relative to Post-April PSIP Plan with Plexos and PowerSimm		
	Plexos Evaluation	**PowerSimm Evaluation**
Oahu E3 Plan	-0.1%	+1.4%
Oahu E3 Plan with LNG	-7.6%	-11.2%
Maui E3 Plan	-7.0%	-8.2%
Hawaii E3 Plan	-9.4%	-2.4%

Table 3: Comparison of evaluation of plans by Plexos and PowerSimm

3. Flexible Thermal Generation

The transition to a high renewable energy portfolio paradoxically requires the restructuring Oahu's thermal generation to a more flexible fleet. While at first blush one may see little merit in new thermal generation, this investment remains a critical component of the thermal transition to a 100% renewable portfolio. Even in 2045, variable meteorologies create conditions, which necessitate the use of thermal generation.

With high intermittent renewable penetration, the operating patterns of dispatchable generation alter significantly. Instead of providing power at steady rates throughout the day, thermal generation is expected to ramp up and down rapidly to address the imbalances between load and supply that comes from solar and wind generation's volatility. This section will elucidate the need for flexible thermal generation. Then this section will present Ascend's optimized additions to Oahu's thermal fleet, as well as a comparison between PowerSimm's calculations of the total costs for (1) Oahu's existing thermal fleet with no updates, (2) Oahu's Ascend-optimized flexible thermal fleet, and (3) the updated flexible thermal fleet contained in the Oahu Post-April PSIP Plan. Ascend will provide the total costs of these three thermal fleets under conditions of perfect and imperfect foresight.

3.1. The Need for Flexible Thermal Generation

Since the availability of wind and solar generation is contingent on weather patterns and their output is taken before thermal generation, the operating patterns of thermal generation have to undergo a shift in a system with high penetration rates of intermittent renewable generation. Thermal generation shifts from operating at base load to operating on a more flexible and irregular basis, serving load during the periods when wind and solar cannot provide sufficient generation to meet load.

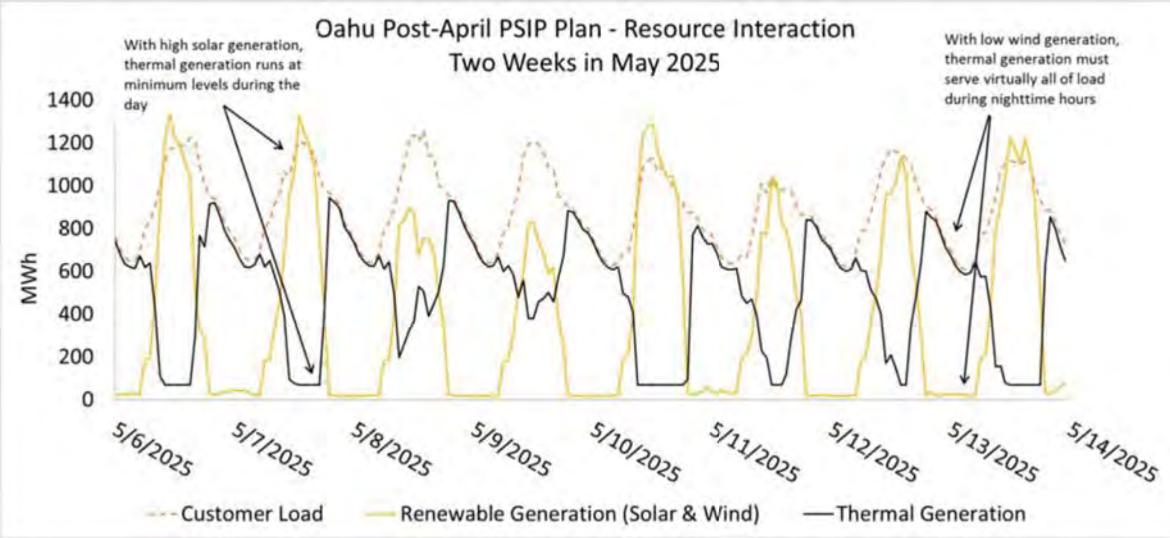


Figure 5: Resource interaction for two-week period in May, 2025.

Figure 5 presents a typical example of thermal generation operations under Oahu's growing levels of intermittent renewable penetration in 2025. Thermal generation is very low when solar generation peaks during the middle of the day and is thus able to serve the majority of load. Since, during solar's off-peak hours, there is very little wind generation, thermal generation must ramp up to meet load, virtually serving all of load for the majority of the evening and night-time hours.

Under such operating conditions, having thermal generation units that are relatively inflexible can incur significant production costs. With higher intermittent renewable penetration, the production costs with an inflexible thermal fleet are higher than with a flexible fleet because inflexible generators, such as steam generators, will be required to come online to serve load for relatively short durations during peaking conditions. Steam units have long minimum-run times, usually around 12 hours. Thus, if additional thermal generation is only necessary for 4 hours, steam units will have to continue to run for 8 more hours at minimum generation. Since steam units run much more inefficiently at minimum generation than at maximum generation, production costs rise in such scenarios. On the other hand, a flexible thermal unit such as a combined cycle generator (CC) has a minimum run time of 1-hour. Thus, if additional thermal generation is only necessary for 4 hours, CCs can shut off immediately thereafter, incurring no additional costs.

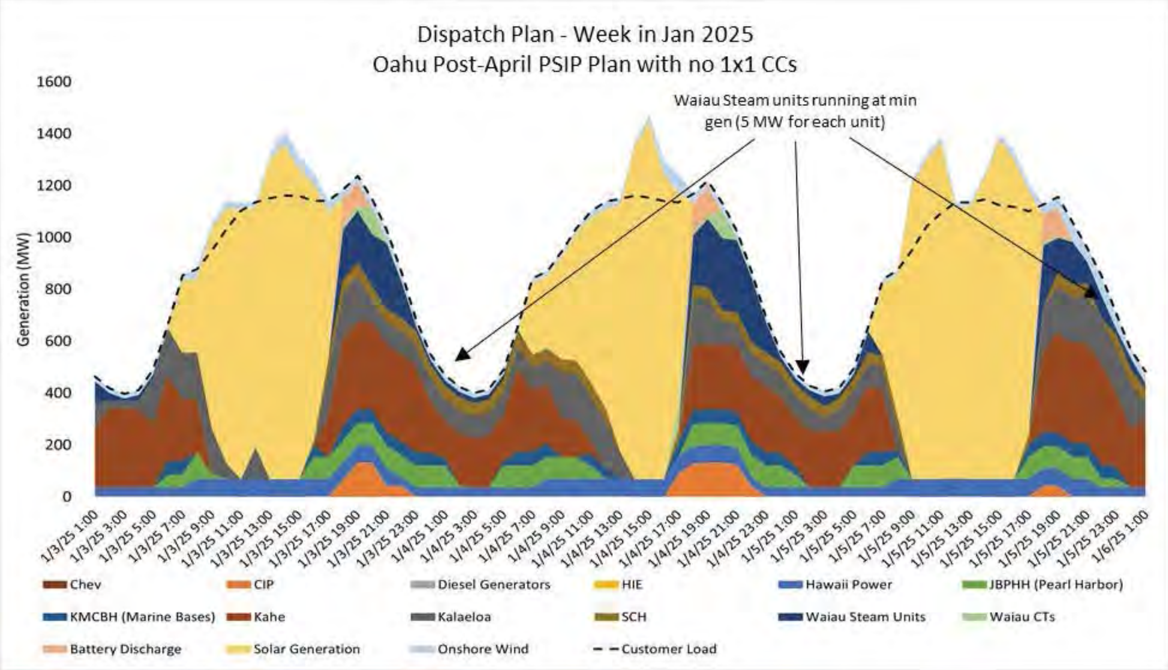


Figure 6: Dispatch Plan without 1x1 combined cycle generators, January, 2025.

Figure 6 provides an example of rising production costs without flexible thermal generation. The most important aspect to note in this dispatch plan is the thermal generation of the Waiau steam units (shaded dark blue). On January 23rd, the Waiau units come online at approximately 5:00 p.m., when solar generation (shaded yellow) declines, in order to meet load. After 11:00 p.m. the Waiau units' generation is no longer necessary to meet load, but, since they have a minimum run-time of 12 hours, they have to continue to run at minimum generation (5 MW per unit) until 5:00 am. At these must-run generation levels, the steam units operate at a relatively inefficient heat rate (21 MBtu/MWh) compared to when they operate at maximum capacity (10-11 MMBt/MWh). Thus, keeping these units running at minimum generation incurs significant costs.

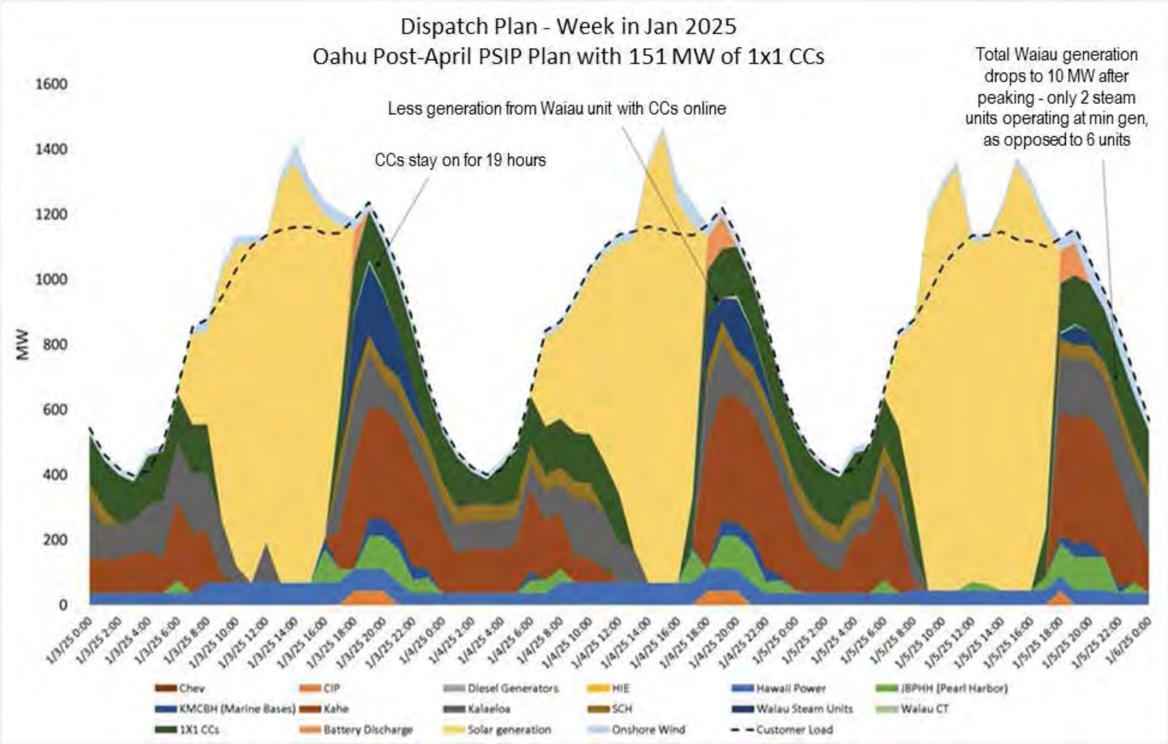


Figure 7: Dispatch plan with 151 MW of 1x1 combined cycle generators, January, 2025.

Figure 7 shows the dispatch plan for the same week with 151 MW of 1x1 CCs included (shaded dark green). Compared to the plan without the CCs, the utilization rate of the Waiu steam units drops considerably. The Waiau steam units do come online for peaking hours, but less of them do; thus they incur less heat rate penalties. Moreover, the CCs displace the generation of the Waiau combustion turbine (CT) generator (represented by the light green sliver above the Waiau steam units) during peak conditions, as they are more efficient than CTs in providing flexible generation.

In sum, there is a compelling need to have a more flexible fleet to address the imbalance between supply and load that comes with high intermittent renewable penetration. Without the flexible thermal fleet, production costs will be significantly higher because a considerable amount of steam generators will be compelled to come online for a relatively short duration during peaking conditions, and then remain running at minimum generation for a substantial block of hours when their generation is no longer necessary.

3.2. Optimal Thermal Generation Mix

Figure 8 compares the total costs for thermal generation of three thermal mixes for Oahu: (1) the optimized thermal mix plan developed by Ascend, (2) a thermal mix that does not upgrade Oahu's thermal fleet, (3) the Post-April PSIP Plan thermal mix. Ascend's optimal thermal mix calls for the addition of 1 CC in 2025, 1 internal combustion engine (ICE) in 2025, 2 ICEs in 2026, 1 CC in 2027, 1 ICE in 2030, and 1 ICE in 2035. The Oahu Post-April PSIP Plan adds 5 151 MW CCs in 2025, 2027, 2030, 2032, and 2035 respectively. The CC capacities are 151 MW, while the ICE capacities are 16.8 MW.

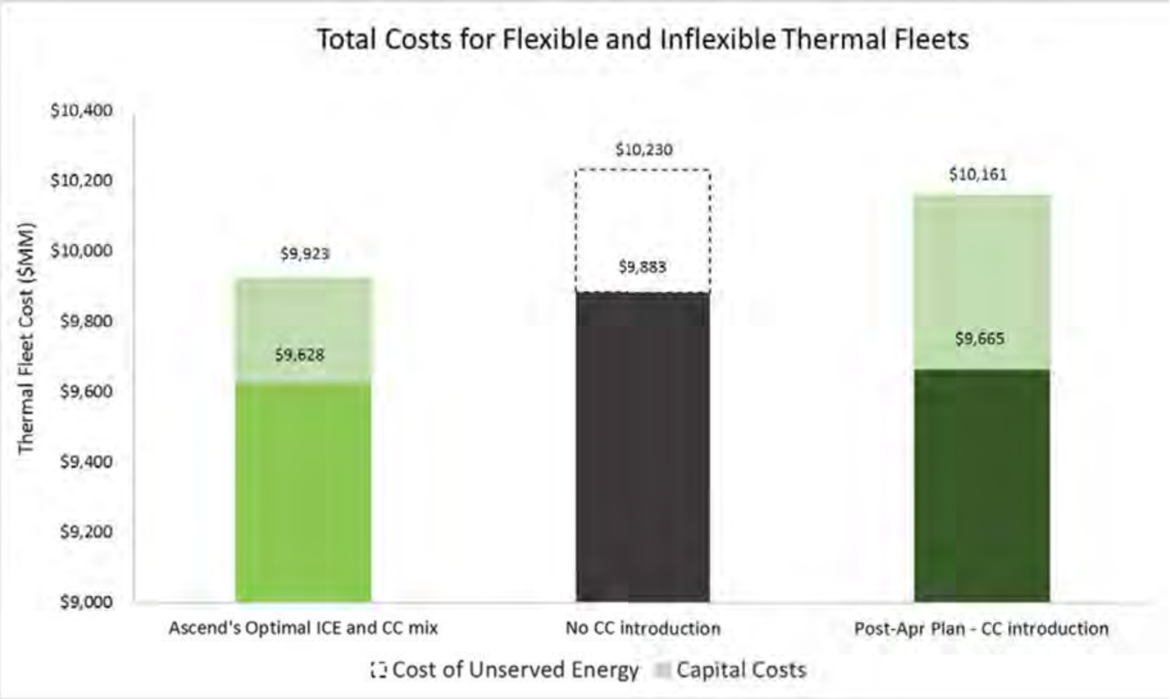


Figure 8: Total costs for flexible and inflexible fleets.

The lower bar in each plan represents the total production costs of each thermal mix. Since there are additions to the thermal fleet in both the Post-April PSIP Plan thermal mix and the Ascend thermal mix, the capital costs for those additions are included as well in the total costs, as indicated by the light green bar stacked on top of production costs. Ascend also analyzed the level of resource adequacy provided by each of these thermal mixes, and though the thermal mix without upgrades (represented by the middle bar) has no capital costs, such a thermal mix fails to meet resource adequacy standards, placing Oahu at substantial risk for power outages. Thus, penalties of $10,000 per forecasted MWh short were added to the total costs. Relative to the thermal mix with no upgrades to the fleet, the Ascend thermal mix provides $342 M less in total costs, while Post-April PSIP Plan's thermal mix provides $69 M less in total costs.

3.3. Introducing Imperfect Foresight

The thermal generation costs presented in the prior section were calculated under conditions of perfect foresight. Perfect foresight entails that the production cost model can see the future states of load, solar generation and wind generation, and decide accordingly how to employ thermal generation units. In reality, however, operators do not have this information; thus, to be prepared for any sudden dips in renewable generation or spikes in load, operators tend to leave thermal generators online at minimum generation for longer stretches. PowerSimm's modeling of imperfect foresight accounts for such operating practices. Figure 9 below compares the results of each thermal mix with perfect and imperfect foresight.

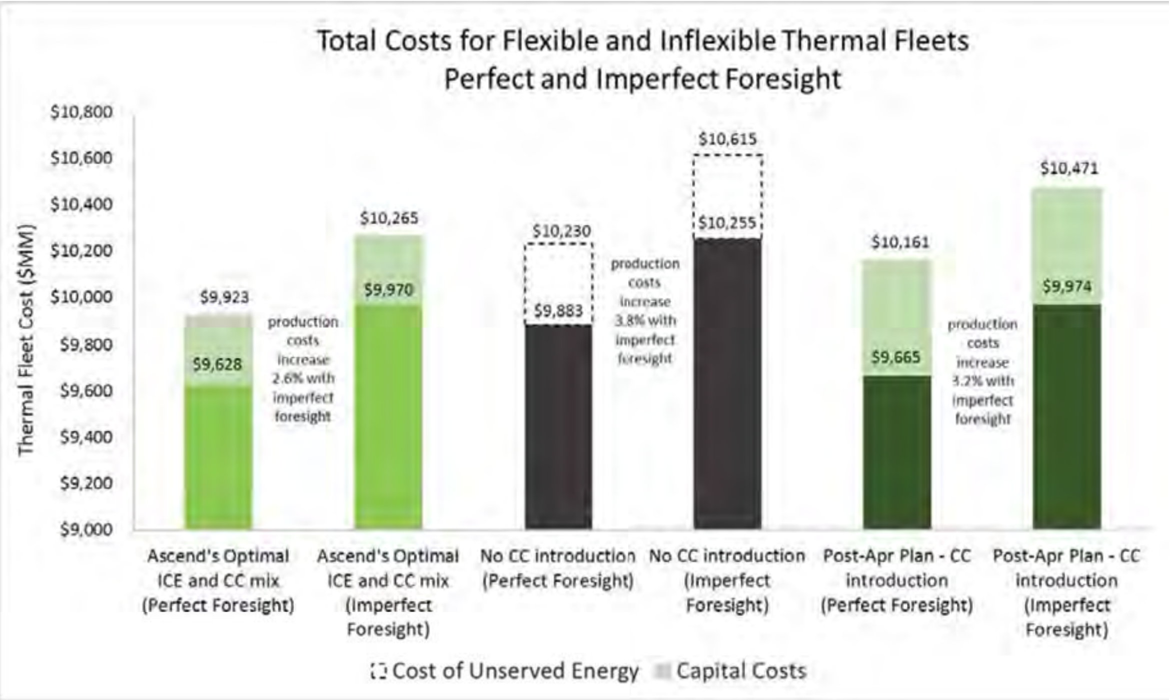


Figure 9: Total costs for flexible and inflexible fleets with perfect and imperfect foresight.

With imperfect foresight, costs increased by the greatest percentage for the thermal mix with no upgrades. The thermal fleet without any introduction of ICEs or CCs incurs the most additional costs with imperfect foresight because its relatively inflexible generators must stay online at minimum generation for longer periods of time. On the other hand, the flexible fleets are able to start up and shut down, and ramp up and ramp down at much faster rates, enabling them to run at more efficient heat rates under conditions of imperfect foresight.

Ascend's optimal thermal mix has a smaller increase in costs with imperfect foresight (2.6%) compared with the Post-April PSIP Plan's thermal mix (3.2%). Ascend's optimal thermal mix contains two CCs and 5 ICEs, while the Post-April PSIP Plan's mix contains 5 CCs. ICEs are the more flexible generator; thus the prevalence of them in Ascend's fleet causes the lower increase in costs with imperfect foresight.

4. Ascend-Developed Plans and Final Comparisons of Each Island's Plans

To update and improve upon the three Post-April PSIP Plans, Ascend used PowerSimm to develop new, optimized plans. In the new plans developed by Ascend, one of the main features is the inclusion of load-shifting batteries. Thus, this section will first demonstrate the benefits of including load-shifting batteries in energy portfolios with high levels of renewables. Second, this section will discuss resource adequacy, highlighting the need to maintain adequate thermal reserves in the case of an extreme event. Third, this section will present the details of PowerSimm's analysis of the Ascend-developed plans for each island system, as well as a comparison of these plans to the non-Ascend plans.

4.1. Load-Shifting Batteries

One of the main challenges of shifting to a 100% renewable portfolio is the intermittent nature of renewable generation. For instance, a renewable portfolio with a large amount of solar will generate excess power during the day, but too little at night. Load-shifting batteries provide a means to store that excess day-time generation and discharge the power at night. In this way, when shifting to a 100% renewable portfolio, batteries become a crucial and cost-effective tool for meeting load. This subsection will further elucidate the advantages of utilizing load-shifting batteries; then it will present the assumptions Ascend made regarding the inclusion of load-shifting batteries in the PowerSimm model.

4.1.1. The Case for Batteries

To demonstrate the advantages of including load-shifting batteries in portfolios with a large percentage of renewables, the following figures show PowerSimm simulation results of battery charge/discharge cycles in relation to customer load, renewable generation, and thermal generation for two different time periods for a single stochastic simulation. These two time periods were specifically chosen to demonstrate times when there are sufficient renewables and battery capacity to minimize the need for thermal generation. However, even at these levels of renewables and batteries, there are still times when there is insufficient renewable energy (due to, for example, extended periods of light winds or cloudy weather) to eliminate the need for thermal generation.

Figure 10 shows a time (May 2045) when there is more than adequate renewable generation. In this figure, there are prolonged periods where renewable generation far exceeds the customer load. During these times, batteries can be charged to minimize dump energy. However, once the batteries reach their capacity, charging stops and any additional renewable energy is "dumped", or not utilized. PowerSimm modeling recognizes that capturing all dump energy is not the optimal solution. Building excessive battery capacity at some point will cost more than the value of the energy it is designed to store.

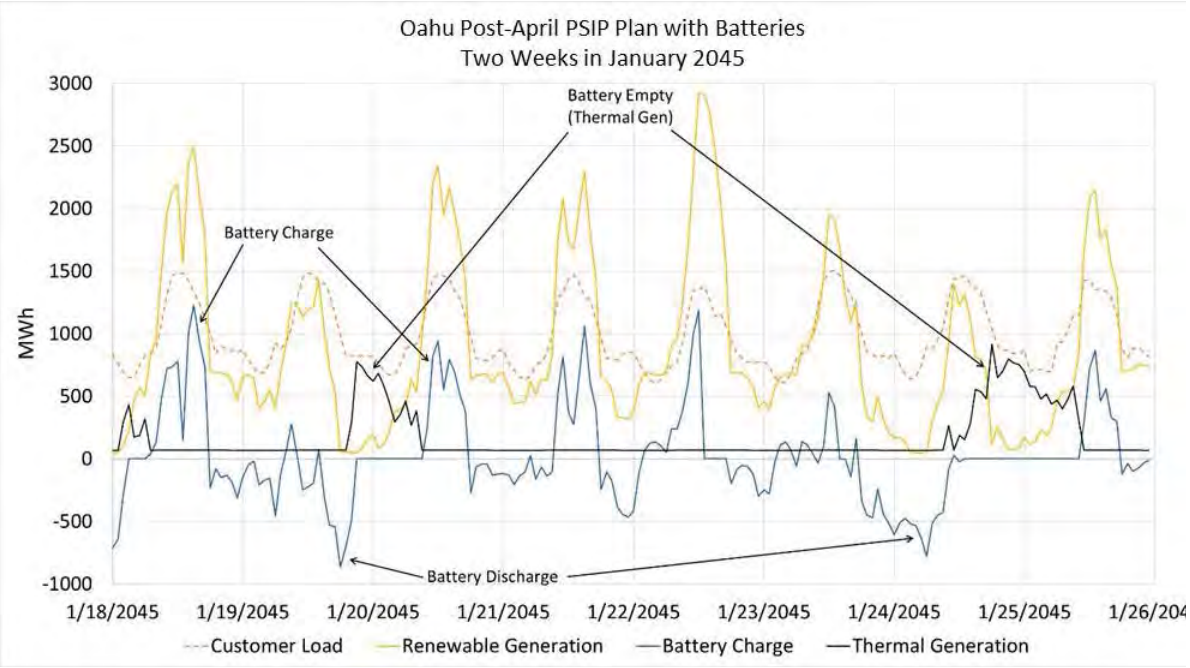


Figure 10: One stochastic simulation for a two-week May 2045 with 7,000 MWh batteries.

If it were not for the load-shifting batteries added to this portfolio, a significant amount of the energy generated by solar renewables during the day would be wasted since there would be no mechanism to store this energy. Moreover, the stored energy is then utilized when solar generation is not sufficient to meet load. This is indicated in Figure 10 when the battery charge is negative, that is, discharging its stored energy in order to meet net-load. Without load-shifting batteries, there would be insufficient renewable energy resources whenever solar stops generating at night, thus requiring thermal generation to meet customer demand. Not only would this thermal generation in 2045 require burning expensive biofuels, but it would also require expensive plant startups or running power plants at a sub-optimal generation level to prevent startups and shutdowns.

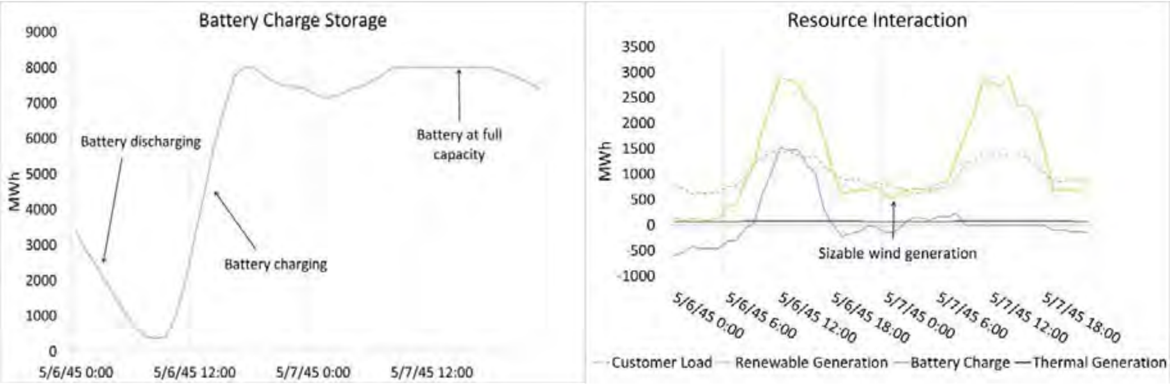


Figure 11: Comparison of battery dynamics for May 6th and 7th, 2045. The diagram to the left indicates the battery state of charge. The diagram to the right indicates the resource interactions between renewable energy (yellow line), customer load (red dashed line), thermal generation (black line) and batteries (blue line).

Figure 11 provides a more in-depth look at battery dynamics on May 5th and 6th, 2045. As seen in the right diagram, renewable generation is very low from midnight to sunrise on May 6th; thus the battery has to discharge. In the left diagram, the battery discharge is presented by the decreasing slope, indicating that the battery discharged around 3,000 MW. When solar generation begins to exceed customer load at approximately 10:00 a.m. (see right diagram), the battery starts to charge up to its full capacity of 8,000 MWh. There is more wind generation during the night of the 6th and 7th than the prior night. Thus the battery has to discharge relatively little of its stored energy, and even before sunrise it begins to recharge to full capacity. As a result, when solar generation comes online on May 7th, the battery absorbs only a minimal amount of the generation in excess of load, and then ceases to charge during the period in which solar generates the most dump energy. The left diagram confirms that the battery barely charges because it is already at full capacity.

Figure 12 shows the resource interactions between thermal generation, renewables, and batteries in a winter month (January, 2045). When renewable generation exceeds load, batteries are able to absorb the excess energy by charging. When renewable generation is less than load, batteries can help meet load by discharging. However, there are periods when batteries are totally depleted and thermal generation must ramp up to meet load. These scenarios are typically attributable to weather conditions that are either cloudy (minimal solar generation) or still (minimal wind generation). During such time periods, biodiesel must be consumed to provide adequate generation to meet load.

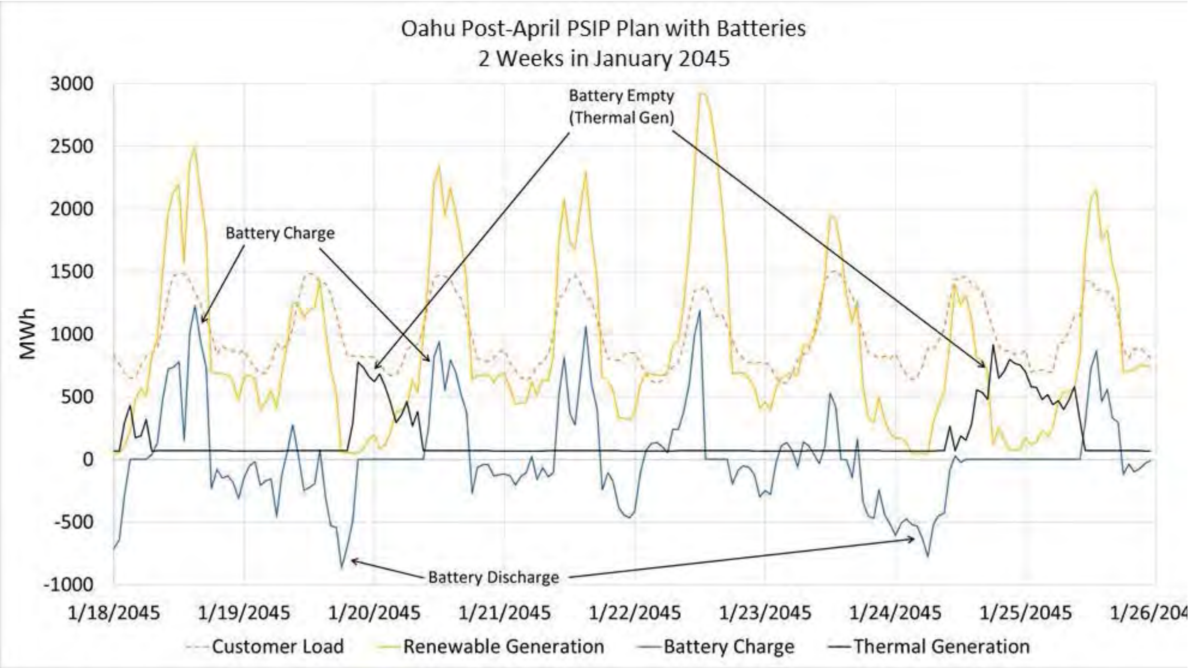


Figure 12: One stochastic simulation for January 2045 with 8,000 MWh batteries.

Figure 13 provides a more detailed view of the dynamics between renewables, batteries and thermal generation for January 24th and 25th, 2045. On January 24th, there is not enough solar generation to meet load, and very little wind generation during the night. Thus the load-shifting battery must discharge the rest of its stored energy early in the day, and thermal generation must come online, eventually serving over 80% of the load during the night of the 24th and 25th. However, during the day of the 25th, renewables exceed customer load, enabling batteries to charge.

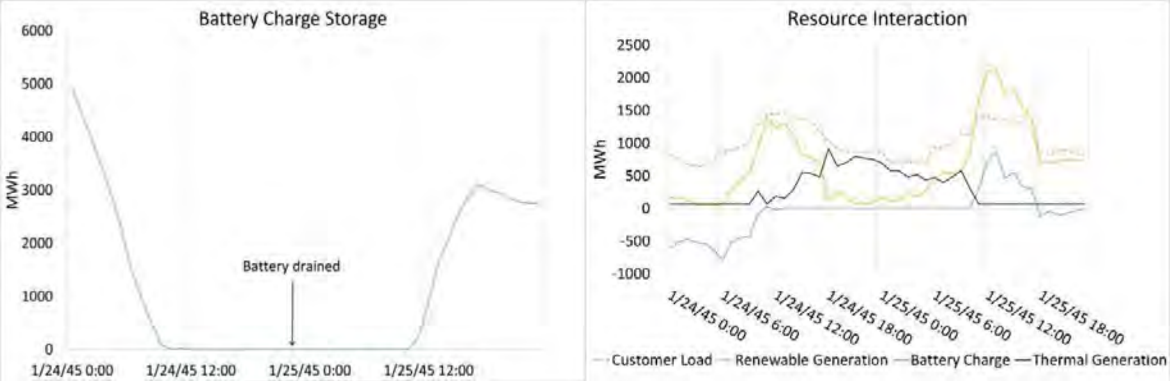


Figure 13: Comparison of battery dynamics for January 24th and 25th, 2045. The diagram to the left indicates the battery state of charge. The diagram to the right indicates the resource interactions between renewable energy (yellow line), customer load (red dashed line), thermal generation (black line) and batteries (blue line).

Thus, by 2045 load-shifting batteries do not eliminate thermal generation, but they do minimize the need for it. Thermal generation will be especially crucial during extended periods of low renewable generation (e.g. during a series of cloudy days where batteries are not able to recharge with adequate solar generation). Moreover, even during periods where there is sufficient renewable generation to meet load, thermal generation is always running at a steady, though minimal level. To economically meet the thermal generation requirements under conditions of higher intermittent renewable penetration, Oahu would have to (1) update its existing thermal fleet with flexible thermal units, as detailed earlier in section 3, and (2) maintain sufficient thermal generation capacity in order to ensure resource adequacy. This second component will be gone over in section 4.3.

Load-shifting batteries provide a cost-effective way to smooth over the variability of intermittent renewable generation by storing excess energy, also referred to as dump energy, that would otherwise be lost. Below, Figure 14 addresses this point directly by showing the amount of dump energy per year with and without batteries. The Oahu Post-April PSIP Plan optimized with batteries reduces dump energy by approximately 120 GWh in 2025, and by over 400 GWh in 2040.

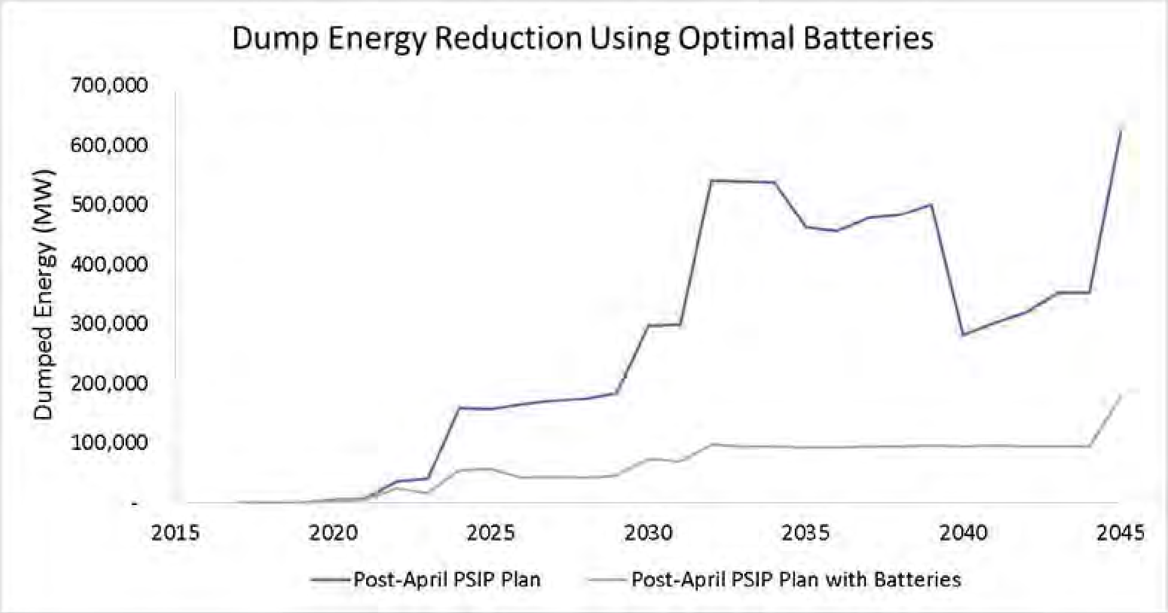


Figure 14: Dump energy for the Oahu Post-April PSIP Plan without batteries vs. with batteries

To summarize, the inclusion of load-shifting batteries in portfolios with high levels of renewables has substantial advantages. Load-shifting batteries can store large amounts of excess renewable energy generated during the day (dump energy that would otherwise be lost) and discharge that energy to meet load at times when renewable generation cannot meet load. However, though load-shifting batteries mitigate the need for thermal generation, they do not entirely eradicate this need.

4.1.2. Battery Assumptions

While including batteries in the PowerSimm modeling framework, Ascend made a series of assumptions about load-shifting batteries. First, Ascend assumed a 15-year lifetime for load-shifting batteries. Second, because batteries can be refurbished, Ascend assumed that the value of a battery at the end of its lifetime is 50% of the install cost at that time. Third, assuming an 8% interest rate and that battery installation costs from 2045 and beyond remain unchanged at $306/KWh, Ascend calculated the effective installation cost as follows:

$$EIC_t = IC_t - \frac{1}{2} PV(IC_{t+15}, 8\%)$$

Where EIC is the effective installation cost for a particular year, IC is the installation cost for a particular year, and PV is the present value function in Excel. Using this method, Ascend calculated the effective installation cost (EIC) for each year using battery installation costs (IC) provided by the Companies in the April 2016 PSIP filing. These costs for each year are shown in Table 4 below:

Year	Install Cost ($/KWh)	Effective Install Cost ($/KWh)	Year	Install Cost ($/KWh)	Effective Install Cost ($/KWh)
2016	660	607	2031	343	295
2017	615	562	2032	338	290
2018	565	513	2033	333	286
2019	524	472	2034	329	282
2020	487	436	2035	326	278
2021	461	411	2036	323	275
2022	440	390	2037	320	272
2023	422	372	2038	317	270
2024	406	357	2039	315	268
2025	393	344	2040	313	266
2026	382	333	2041	312	264
2027	372	323	2042	310	262
2028	363	315	2043	309	261
2029	355	308	2044	307	260
2030	349	301	2045	306	258

Table 4: Cost and Effective Cost of battery installation by year

Ascend also assumed that, to prevent damage from occurring, load-shifting batteries will never discharge below 20% of their capacity. To account for this assumption, there was a 20% adder included in the capital costs of batteries. However, it is important to note that the battery buildout plans shown in the following subsections show the *functional* battery capacity, that is, the battery capacity that can fully discharge. The *actual* battery capacities, which determine the capital costs, are always 20% greater than the *functional* battery capacities, which are shown in the figures below.

All of these battery assumptions were used across all new plans that include load-shifting batteries.

4.2. Marginal Renewable Resource Analysis

PowerSimm was also used to conduct a marginal analysis of an additional MW of renewable generation for the Oahu Post-April PSIP Plan. For these calculations, 1 MW of renewable generation was added to the Oahu portfolio to determine the effective cost of the additional power from each 1 MW addition. The resulting levelized cost of power (i.e. cost of power inclusive of both variable and capital costs over the lifetime of the generation unit) was then compared to the levelized cost of power from traditional thermal generation assets available in the Oahu portfolio. The results from this analysis are shown in Figure 15.

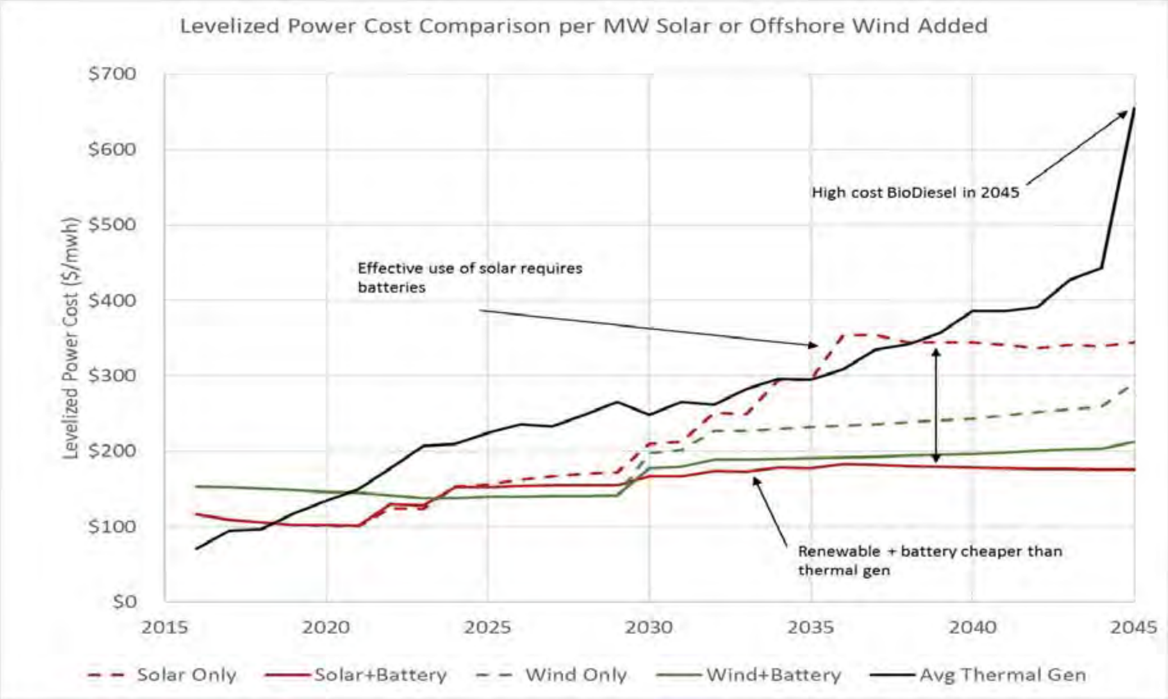


Figure 15: Compares levelized cost of different types of generation with and without batteries

Figure 15 shows that renewables become more cost-effective early on relative to the variable cost of thermal generation, excluding all fixed costs. Load-shifting batteries combined with solar start adding significant value in 2025, by capturing dump renewable generation and serving to reduce the cycle demand on thermal generation. Load-shifting batteries combined with wind generation begin to add value by 2030, when offshore wind generation comes online. That being said, load-shifting batteries only account for battery benefits on an hourly scale. On the other hand, regulation batteries, which incorporate battery usage on a minutely scale, provide cost savings much earlier on.[3] By 2035, adding renewables without adding battery capacity for storage does not make economic sense, especially for solar. Large differences upwards of $100 per MWh can be realized by simply adding sufficient battery storage along with solar. Thus the ability of Oahu to realize high renewable generation rates become a function of battery costs continuing to decline.

Additionally, Figure 15 shows that solar combined with batteries and wind combined batteries provide similar costs through time. Ascend's analysis has solar becoming slightly cheaper than wind after 2030; yet which resource will actually provide cheaper power in the future is an open question. If there is a steeper decline in the costs of offshore wind, then it could be more cost-effective to opt for further wind generation, diminishing to some extent the need for batteries, as a MW of wind generation requires about half the storage level as a MW of solar generation. If there is a steeper decline in the costs for batteries, the combination of solar generation and batteries would become even more appealing.

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[3] See section 5.2.2 for more on regulation batteries.

4.3. Resource Adequacy

Due to the intermittency of renewable resources, there is always the potential for extended periods of still and/or cloudy weather that severely curtails solar and wind generation. Under such extreme weather conditions, the energy system has to be able to continue to meet load reliably. Central to maintaining resource adequacy under all weather conditions is recourse to sufficient dispatchable generation capacity.

This section will present probability distributions of thermal generation in 2045, as produced over numerous weather simulations, for both the Oahu Post-April PSIP Plan and the Oahu Post-April PSIP Plan with Batteries. Then, this section will assess the Loss of Load Probability (LOLP) (i.e. the probability of outages due to load exceeding supply) for both Oahu and Maui under the Post-April PSIP Plan, the Ascend Plan, and the E3 Plan.

Figure 16 displays the probability distribution of thermal generation in 2045 under the Oahu Post-April PSIP Plan.

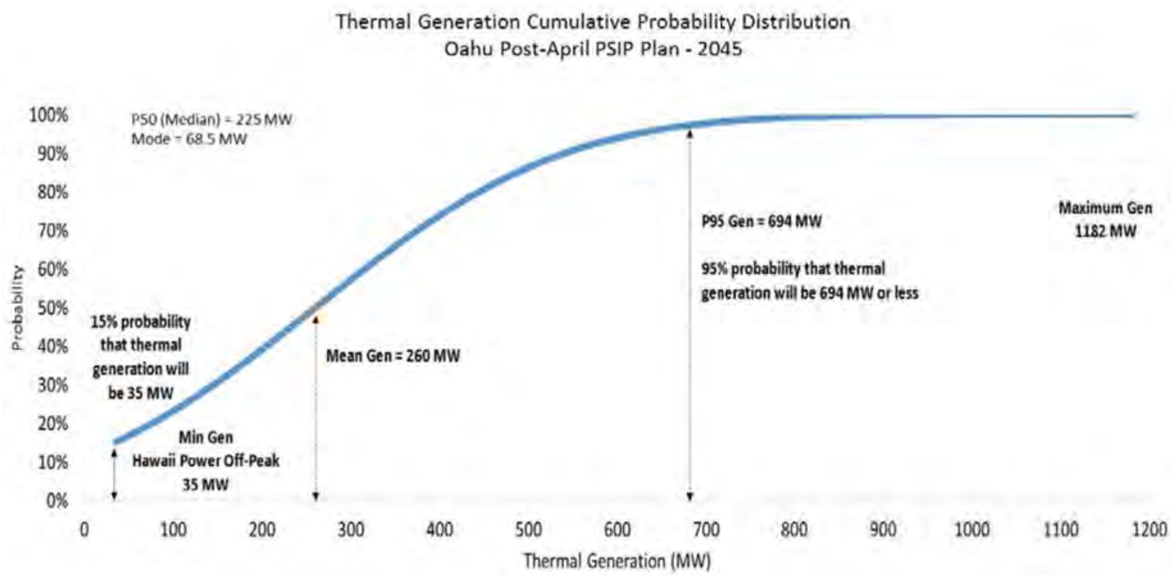


Figure 16: Probability distribution of thermal generation requirements over distinct weather simulations for the Oahu Post-April PSIP Plan (without optimized batteries).

In 2045, the amount of thermal generation most often required (i.e. the mode) is forecasted to be 68.5 MW. There is, however, also 1% chance in 2045 that Oahu will confront weather conditions requiring 924 MW of thermal generation, and the maximum amount generation Oahu will be expected to serve is 1182 MW, which is 116% of average load for the year. Such extreme scenarios are outliers, but nevertheless Oahu would have to be prepared to meet such scenarios.

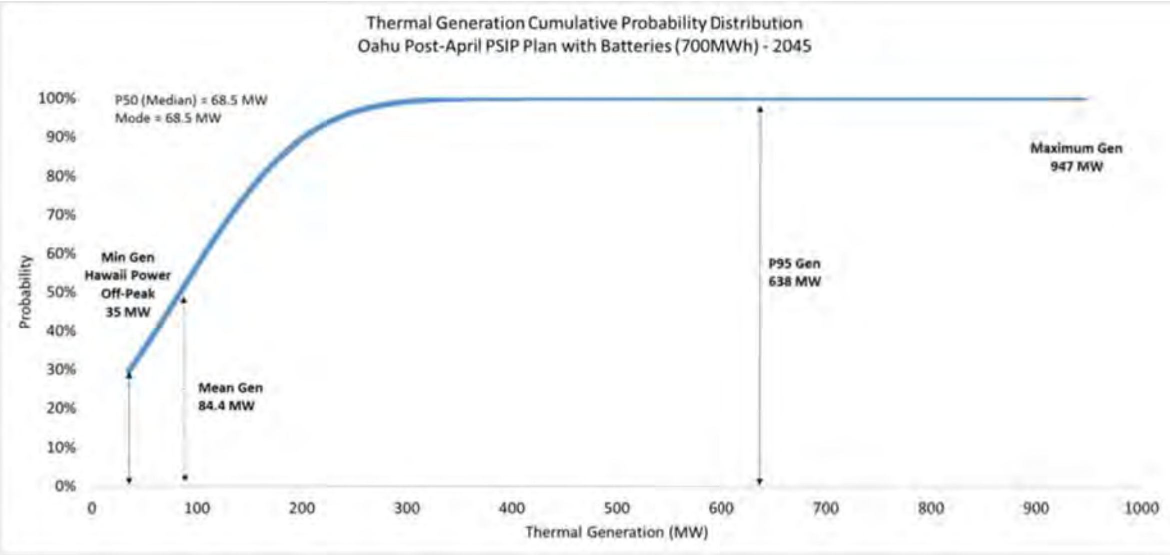


Figure 17: Probability distribution of thermal generation requirements over distinct weather simulations for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

As Figure 17 shows, the addition of 7000 MWh of batteries to the Oahu Post-April PSIP Plan shifts the probability distribution of thermal generation to lower values. With 7000 MWh of batteries, the average amount of thermal generation required in 2045 drops by 68%, from 260 MW to 84.4 MW. The maximum thermal generation required also shrinks from 1182 MW to 947 MW. However, compared to the shrinkage in the average amount of thermal generation required (68%), the reduction in the maximum amount of thermal generation required is not as dramatic (20%). The limited reduction of maximum thermal generation under the Post-April PSIP Plan with Batteries alludes to the limitations of batteries in extreme weather scenarios. If there is an extended weather period with extremely low wind and solar generation, batteries would be unable to recharge from renewable sources. If batteries were to charge, they would do so from thermal generation in excess of load. Thus in such scenarios sufficient thermal reserves would have to be in place to serve the overwhelming majority of load.

Figure 18 and

Figure 19 further emphasize the variability of thermal generation requirements. Ascend ran 20 simulations of thermal generation requirements over a two-week period in May, 2045. Figure 18 and

Figure 19 display the 5th percentile, average, and 95th percentile of the forecasted amount of thermal generation required for the Oahu Post-April Plan and the Oahu Post-April Plan with Batteries (7000 MWh) respectively.

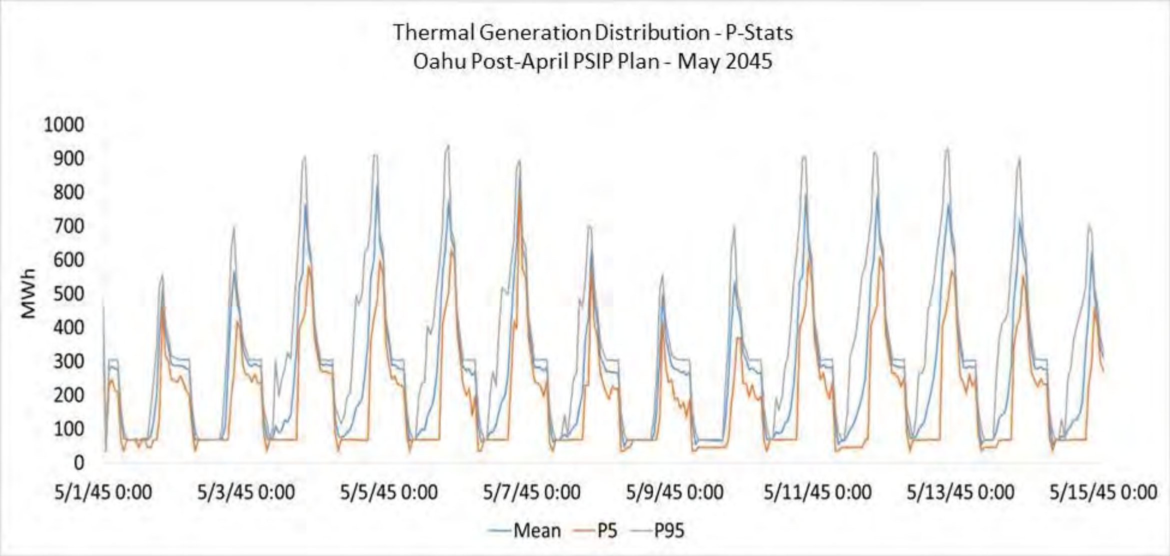


Figure 18: Thermal generation disitribution over distinct weather simulations for two-week period in May, 2045 for the Oahu Post-April PSIP Plan (without optimized batteries).

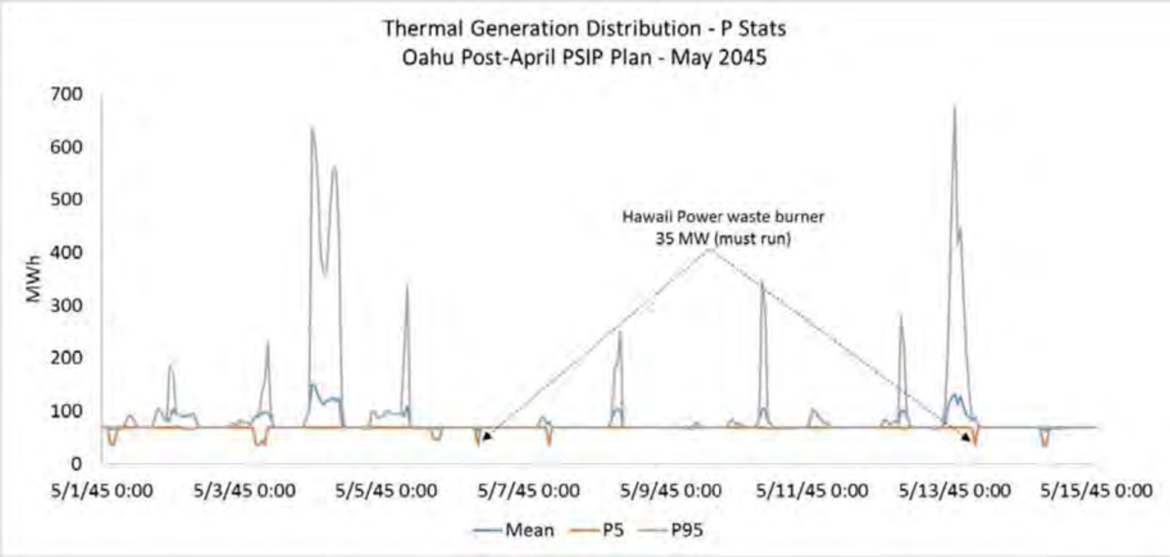


Figure 19: Thermal generation distribution over distinct weather simulations for two-week period in May, 2045 for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

The blue line signifies the average thermal generation requirements when accounting for all the weather scenarios analyzed. The orange P5 line represents the mild weather scenarios that are more favorable to renewable generation (i.e., 5% of the scenarios evaluated have less thermal generation required). The gray P95 line represents extreme weather scenarios that are unfavorable to renewable generation (i.e., 95% of the scenarios examined require less thermal generation). A comparison of Figure 18 *and*

Figure 19 reveals that batteries substantially reduce the amount of additional thermal generation. Without batteries, large amounts of thermal generation are required on a daily basis, irrespective of the weather scenario. On the other hand, with 7000 MWh of batteries, the average amount of thermal generation required remains for the majority of the time around 68.5 MW.

Nevertheless, though the need for a significant amount of thermal generation is curtailed by batteries, there are still extreme weather scenarios to be found in May 2045 where the majority of load will have to be served by thermal generation. In Figure 19, the gray P95 line represents these scenarios, spiking up to 750 MW in some instances.

Figure 20 shows that in a winter month such as January the potential for such spikes in thermal generation increases in frequency and magnitude. For this two-week period in January 2045, there are 5 instances where the extremes scenarios require thermal generation to ramp up to 500 MWh or more, compared to the two-week period in May 2045 found in Figure 19, where there were only 2 such instances. The increase in the frequency and magnitude of price spikes follows from the variability in solar generation during winter months.

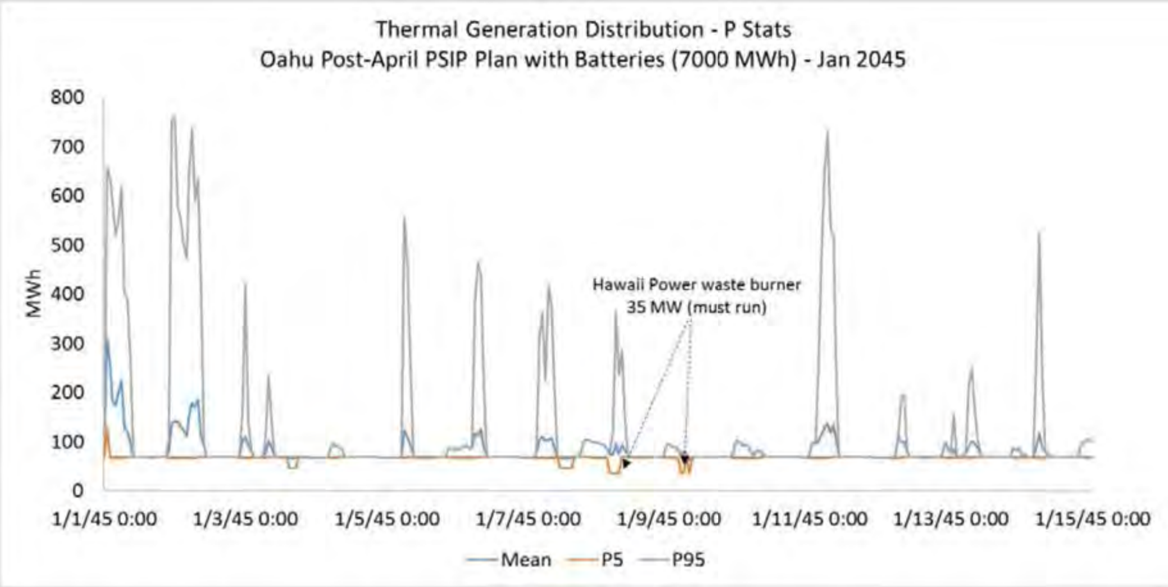


Figure 20: Thermal generation distribution over distinct weather simulation for two-week period in January, 2045 for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

In sum, even with high levels of wind and solar generation, Oahu must maintain thermal generation capacity at levels where it can serve the majority of load in order to maintain resource adequacy. Even if thermal generation is rarely utilized at high capacities, the guarantee of dispatchable energy in periods with low intermittent renewable generation is essential for meeting load reliably. Though load-shifting batteries significantly curtail the need for thermal generation, they do not completely eliminate this need.

4.3.1. Loss of Load Probability: Oahu

Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE) calculates the expected duration of outages and the expected shortfall in generation per year given a system's available resource capacity and forecasted load. LOLP provides an important indicator of a system's level of resource adequacy.

Ascend assessed LOLP for the Oahu Post-April PSIP Plan, Ascend Plan, and E3 Plan. To measure LOLP, Ascend calculated under each plan the expected Loss of Load Hours (LOLH) per year, i.e., the amount of hours when load exceeds supply. Ascend also calculated the shortfall of MW per year. The LOLP analysis uses an advanced integrated simulation framework that captures the joint probability of load and intermittent renewable generation over numerous simulated weather conditions. Because Ascend applies an integrated simulation framework of renewables, load and thermal generation outages, resource deficits can be examined at the 5th, mean and 95th.

NERC's reliability standard for planning in a large integrated power grid is an LOLH of 2.4 hours per year, which corresponds with a total of 24 hours of outages over 10 years.

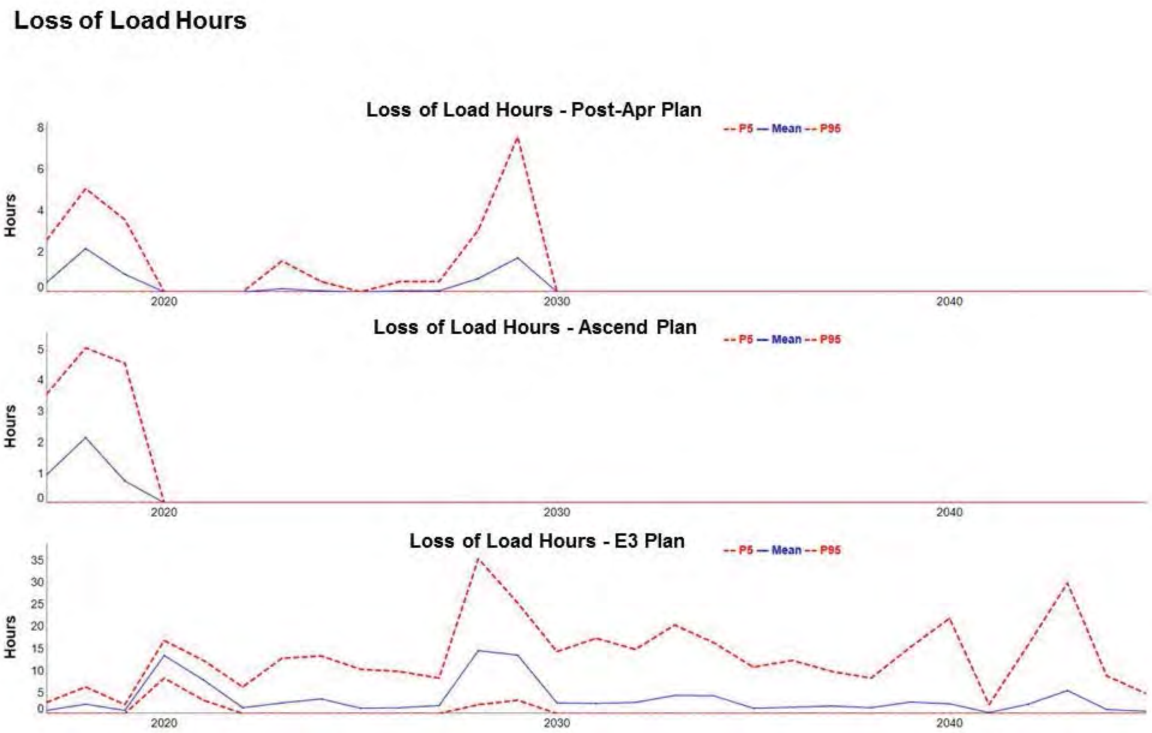


Figure 21: Loss of load hours from 2017 to 2045 for the Oahu Post-April PSIP Plan, Ascend Plan, and E3 Plan.

Figure 21 presents a comparison of the Loss of Load Hours for Oahu under the Post-April PSIP Plan, the Ascend Plan, and the E3 Plan. The mean represents the average hours of outages per year from all the simulations examined. The confidence interval specified by the P5 and P95 endpoints indicate the range of possible hours the portfolio could be short in a given year with a 90% confidence that the true value is within this range.

For the Oahu Post-April PSIP Plan, the average LOLH never exceeds 2.4 hours. However, the P95th bound indicates 3 hours for 2028 and 7.5 hours for 2029 where load exceeds capacity. The increase in expected LOLH results from the retirement of the Kahe 5 and 6 units in 2028. With the introduction of offshore wind in 2030, the LOLH drops to 0 hours from 2030 onwards.

For the Oahu Ascend Plan, the LOLH is relatively similar to the Post-April Plan through 2020. After 2020, however, the Ascend Plan has no expected LOLH. The Ascend Plan adds significantly more renewable generation and batteries than the Post-April PSIP Plan, placing Oahu in a better position to ensure a reliable power supply.

Out of all the plans evaluated, the Oahu E3 Plan has the lowest degree of resource adequacy. From 2017 to 2045 the mean LOLH exceeds 2.4 hours for 40% of the years, and the P95th exceeds 2.4 hours for 96% of the years. The E3 Plan assumes that all steam units will be retired by 2022, and the only update of the thermal fleet contained in the plan is in 2045. The E3 Plan calls for significant levels of batteries, which does assist in providing a secure supply; yet batteries cannot make up for such low levels of thermal generation, which undermine Oahu's ability to furnish enough capacity to meet load under all conditions.

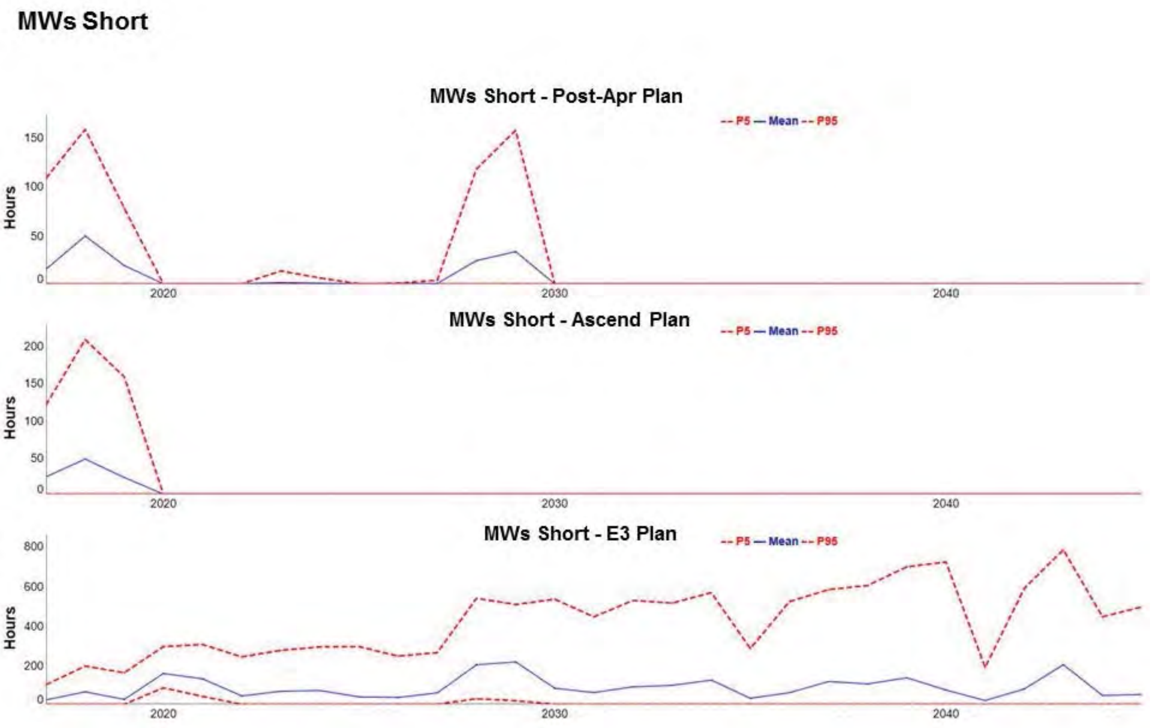


Figure 22: MWs short for Oahu's Post-April PSIP Plan, Ascend Plan, and E3 Plan.

Figure 22 indicates resource adequacy by displaying the expected shortfall of MW per year for each plan. For the Oahu Post-April PSIP Plan, from 2017 to 2019 and from 2028 to 2030 the 95th confidence bound for the shortfall in generation reaches 150 MW, while for the rest of the years there is no or only a negligible expected shortfall in generation. For the Oahu Ascend Plan, from 2020 onwards there is no expected shortfall in generation. For the Oahu E3 Plan, there are no years evaluated without expected shortages. The Oahu E3 Plan's highest mean value for MWs short over the years is 213 MW, which is over 4 times higher than the highest mean values for the Post-April PSIP Plan and the Ascend Plan.

Thus the LOLP results further bolster the conclusion that Oahu will continue to need thermal generation to serve load reliably. A plan such as the Oahu E3 Plan, which proposes early retirement of steam units and no significant updates of the thermal fleet, falls short in providing the necessary resource capacity to maintain the security of the power supply.

4.3.2. Loss of Load Probability: Maui

PowerSimm's analysis of the Maui Post-April PSIP Plan and the Maui Ascend Plan found no expected loss of load from 2017 to 2045 for these two plans. PowerSimm's analysis of the Maui E3 Plan, however, reveals the plan to fall short in meeting resource adequacy standards by considerable margins.

As shown in Figure 23 and Figure 24, the E3 Plan's average LOLH over the weather simulations examined ranges from 22 hours to 36 hours from 2020 onwards. Correspondingly, the E3 Plan's mean shortfall in MWs range from 150 MW to 170 MW from 2020 to 2045.

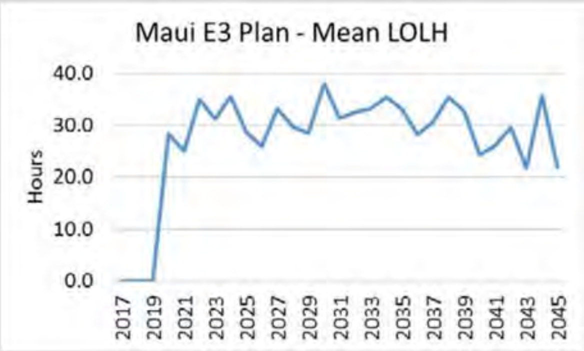


Figure 23: Average LOLH of Maui E3 Plan

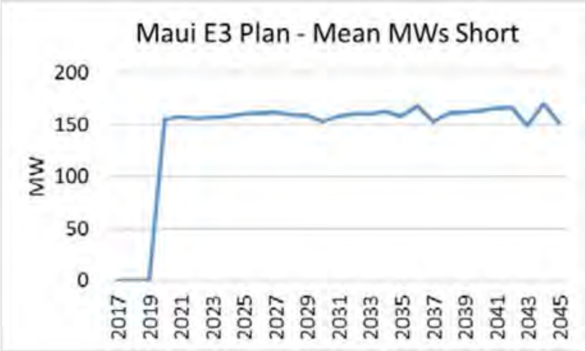


Figure 24: Average MWs short for Maui E3 Plan.

The E3 Plan's drastic increase in LOLH and MWs short in 2020 has two chief causes. Firstly, relative to the Maui Post-April PSIP Plan, the E3 Plan installs 75 MW less of solar capacity and 10 MW less of onshore wind capacity in 2020. Secondly, the E3 Plan retires the 106 MW Maalea CC plant in 2022. The Maalea plant is Maui's primary oil-based generation unit, and retiring this unit puts Maui in a position with very little thermal reserves, causing the island to be heavily dependent on renewable based generation. Thus, under weather conditions unfavorable to renewable generation, the Maui E3 Plan risks significant shortages.

4.4. Oahu Results and Optimized Plans

This subsection will detail the two new plans created by Ascend, the Post-April PSIP Plan with Batteries and the Ascend Plan. The Oahu Post-April PSIP Plan with Batteries was developed by optimizing the levels of batteries in the original plan. The Oahu Ascend Plan was developed by jointly optimizing solar generation, wind generation and batteries in the Post-April PSIP Plan. The end of this subsection will provide a comparison of the NPV portfolio costs of the two Ascend-optimized plans, as well as the Post-April PSIP Plan and the E3 Plan.

4.4.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

This plan is based on Oahu's Post-April PSIP Plan, from which Ascend has developed an optimized battery buildout plan for load-shifting batteries. The optimized battery buildout plan is indicated by the dashed green line in Figure 25 below.

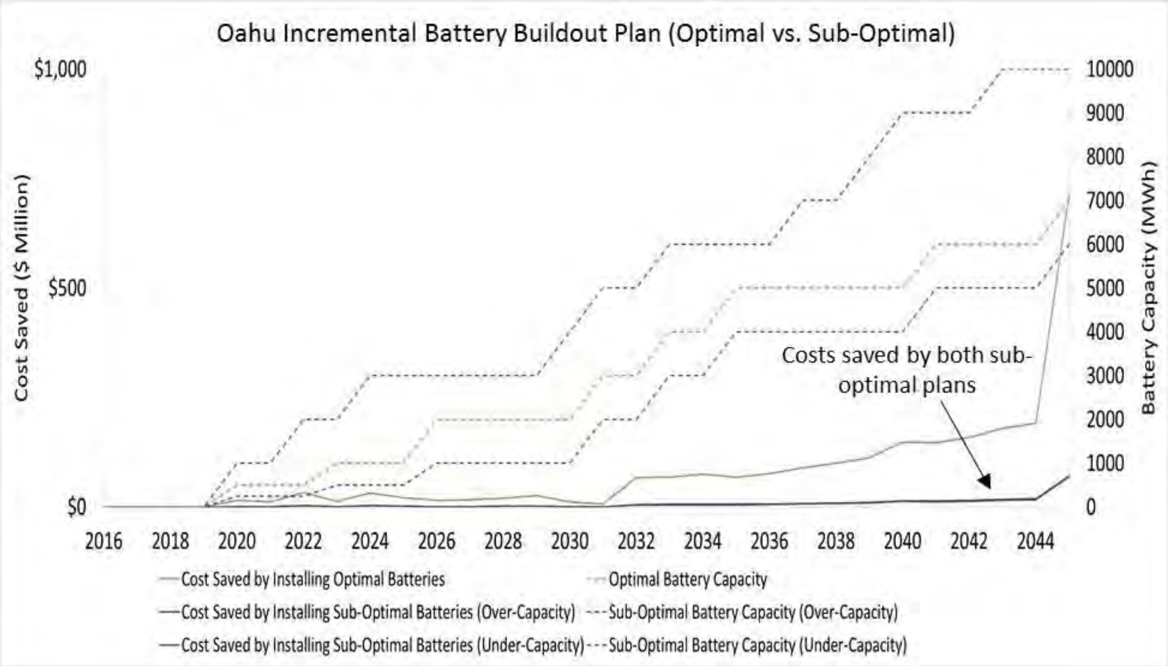


Figure 25: Comparison of two suboptimal battery buildout plans with optimal buildout plan for the Oahu Post-April PSIP Plan.

In Figure 25, three battery buildout plans are presented: the optimal plan, a plan with an over-installation of batteries and a plan with an under-installation of batteries. The dashed lines signify the battery capacity, while the solid lines signify the savings provided by each plan. Beginning in 2032, savings offered by the optimal plan grows steadily. In 2036, while the cost saved by the optimal buildout plan is around $100 M, the cost saved by the two suboptimal plans, which have lines stacked on top of each, are negligible. A comparison between the optimal installation of batteries and sub-optimal under-installation of batteries illustrates that by installing 1000 MWh less of battery capacity, savings drop drastically.

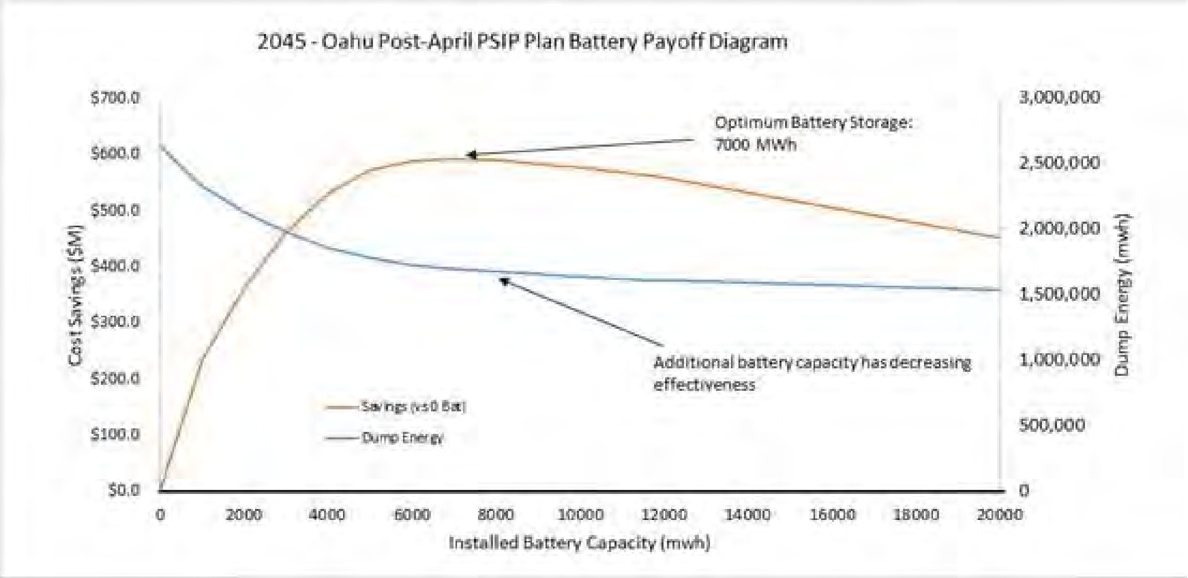


Figure 26: Battery Payoff Diagram for the Oahu Post-April PSIP Plan.

Figure 26 illustrates that additional battery capacity maintains positive marginal economic effectiveness until 7000 MWh. Beyond a capacity of 7000 MWh, the decreasing effectiveness of additional battery capacity in capturing additional dump energy causes savings to decrease.

4.4.2. The Optimization of Renewables and Batteries: The Ascend Plan

Ascend utilized the PowerSimm software to evaluate the concurrent changes needed to jointly optimize solar, wind, and batteries to come up with the renewable plus battery additions that would minimize the overall NPV of the selected portfolio. Sufficient PowerSimm analyses were performed to ensure the optimal mix of solar, wind, and batteries was identified. The existing renewable forecasts from the Oahu Post-April PSIP plan were designated as a starting point to determine how much additional wind, and solar, with corresponding battery storage, would be warranted to minimize overall theme costs.

Figure 27 displays the results from the co-optimization process that Ascend carried out to find the combination of offshore wind, utility solar, and batteries that minimize the NPV of Oahu's portfolio costs.

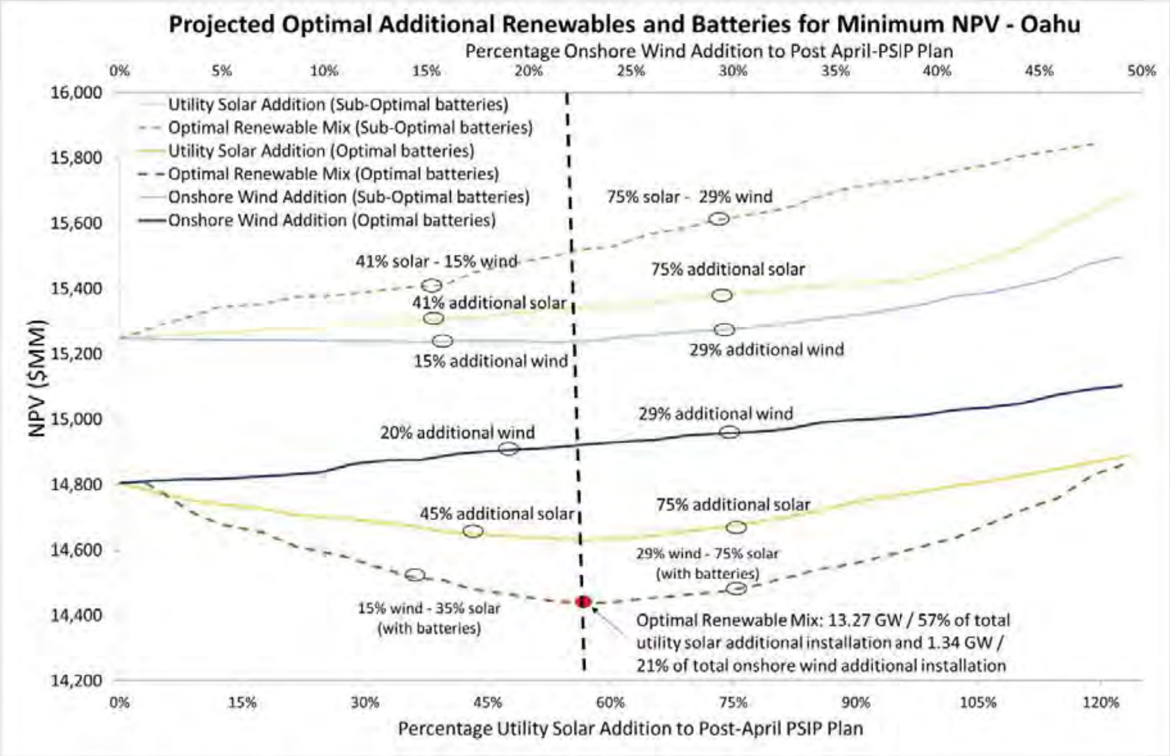


Figure 27: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries.

As shown in Figure 27, the "sweet spot" in the renewable plus battery additions was determined by analyzing a host of paths towards the 100% renewable goal by 2045. This "sweet spot" corresponds to the acceleration of the Post-April PSIP Plan utility PV buildout by 57% and the offshore wind buildout by 21%, in addition to an optimized battery buildout plan. This combination, which is Ascend's optimized plan, results in a NPV reduction of $809 M. It is important to note that to realize this optimal renewable plan, the addition of load-shifting batteries is *required*. Without batteries, as discussed earlier in this report, far too much energy is dumped at times of peak renewable generation, and far too little energy is available during the evening when solar renewables stop generating. Thus, accelerating the introduction of renewables goes hand in hand with the incorporation of load-shifting batteries. If batteries are not included in the plan, the additional renewable generation will actually substantially increase the NPV of Oahu's portfolio costs. With this in mind, the optimal battery buildout plan for the Ascend Plan is displayed below.

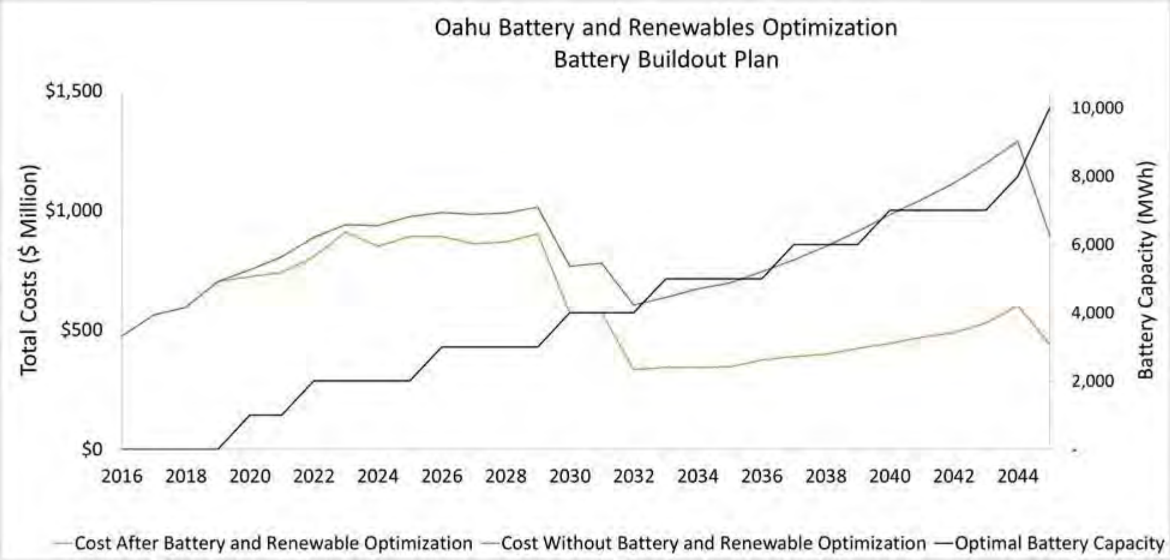


Figure 28: Battery buildout plan for the Oahu Ascend Plan. Battery capacities on the figure do not reflect the additional 20% required to prevent battery damage.

Compared to the Oahu Post-April PSIP Plan with Batteries, the Oahu Ascend Plan has a more aggressive battery buildout plan, calling for 3,000 MWh of battery capacity more than the Oahu Post-April PSIP Plan with Batteries. The higher level of renewables introduced by the Ascend Plan render higher battery capacity levels more economical.

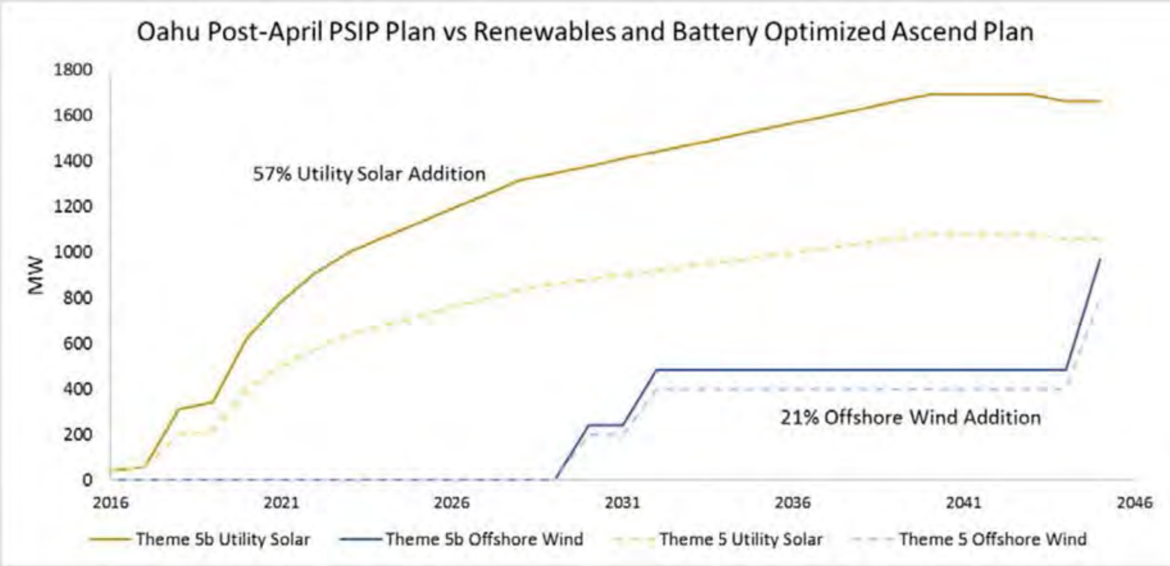


Figure 29: Comparison of renewable generation capacity between the Oahu Post-April PSIP Plan and the Oahu Ascend Plan.

Figure 29 presents the renewable additions of the Ascend Plan relative to the Post-April PSIP Plan. The Ascend Plan contains a 57% increase in utility solar and 21% increase in offshore wind. The marked additions of intermittent renewable generation in the optimized plan stem from the utilization of batteries. Batteries are crucial in rendering the additional intermittent renewable capacity economically beneficial. Solar generation, in particular, has a concentration effect during hours when the sun is shining most directly, resulting in significant amounts of excess energy, off which batteries are able to capitalize.

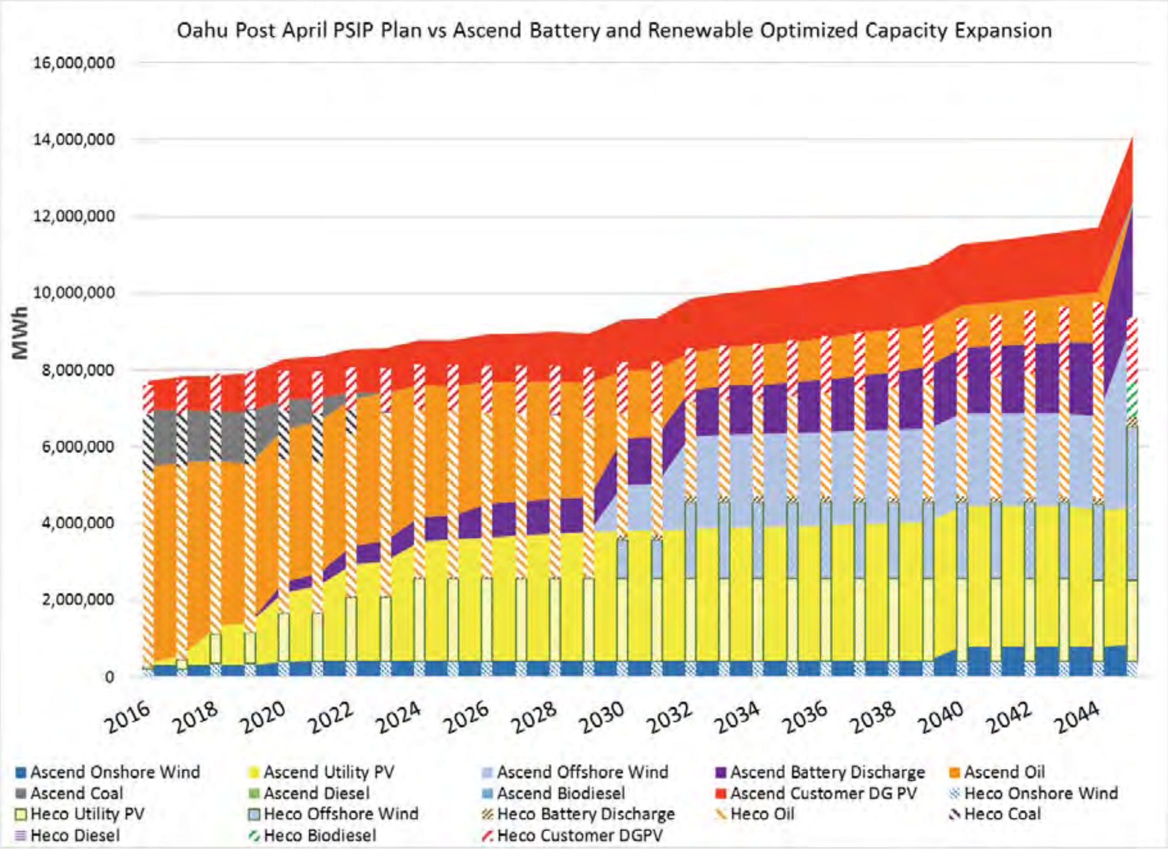
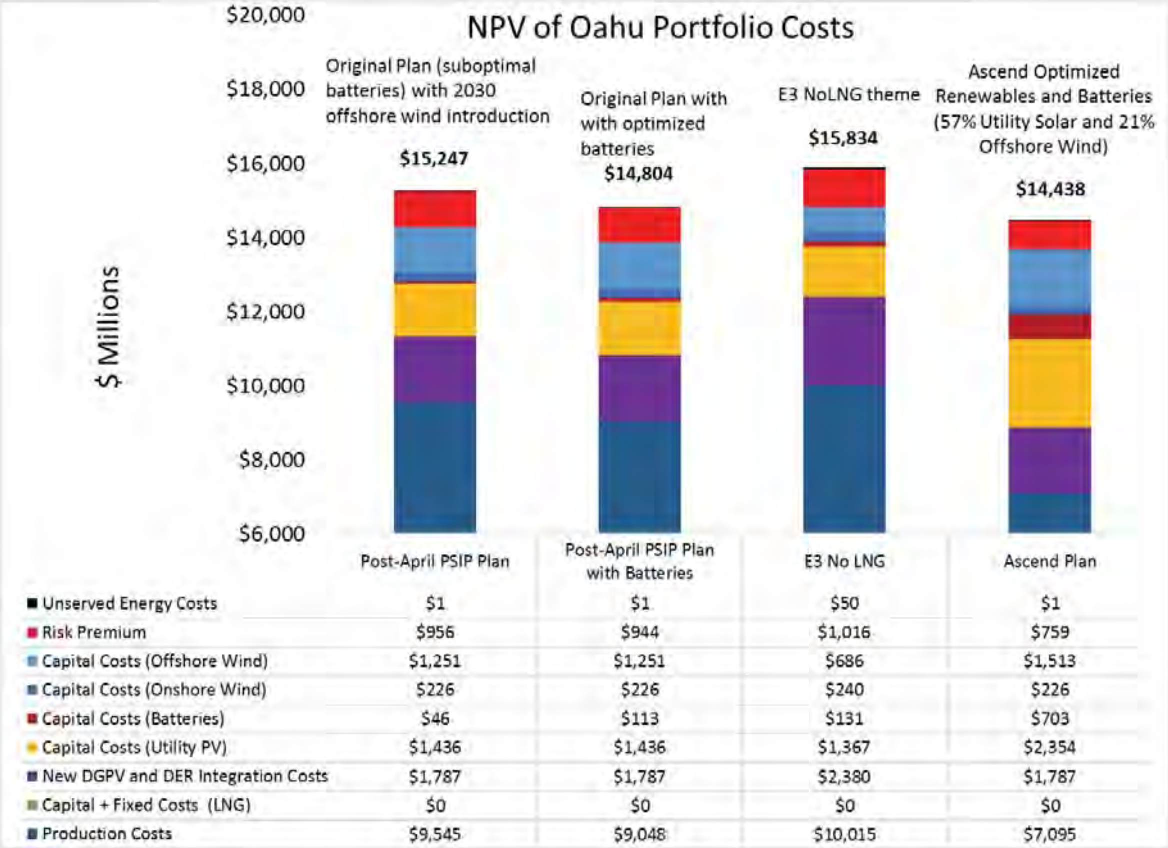


Figure 30: Comparison of the Oahu Post-April PSIP Plan and the Oahu Ascend Plan by resource.

Figure 30 provides a comparison over time of the distinct types of resource generation contained in the Post-April PSIP Plan and the Ascend Plan. The generation from the installed resource capacities for the Post-April PSIP Plan are represented by the bars, while the generation from the installed resource capacities for the Ascend Plan are represented by the shaded areas behind the bars. The two plans start off with identical levels of resource generation. However, by 2020 the overall generation of the Ascend Plan begins to exceed the total generation of the Post-April PSIP Plan, due largely to the accelerated growth of solar generation and the introduction of batteries. With the accelerated growth of solar generation and batteries, the amount oil-based generation by 2032 is two and half times smaller for the Ascend Plan than the Post-April PSIP Plan. By 2040, with additional installations of wind for the Ascend Plan, the amount oil-based generation for the Ascend Plan is nearly three times less than the oil-based generation in the Post-April PSIP Plan.



	Post-April PSIP Plan	Post-April PSIP Plan with Batteries	E3 No LNG	Ascend Plan
■ Unserved Energy Costs	$1	$1	$50	$1
■ Risk Premium	$956	$944	$1,016	$759
■ Capital Costs (Offshore Wind)	$1,251	$1,251	$686	$1,513
■ Capital Costs (Onshore Wind)	$226	$226	$240	$226
■ Capital Costs (Batteries)	$46	$113	$131	$703
■ Capital Costs (Utility PV)	$1,436	$1,436	$1,367	$2,354
■ New DGPV and DER Integration Costs	$1,787	$1,787	$2,380	$1,787
■ Capital + Fixed Costs (LNG)	$0	$0	$0	$0
■ Production Costs	$9,545	$9,048	$10,015	$7,095

Figure 31: NPV of Portfolio Costs for Oahu's four plans.

As Figure 31 shows, adding an optimized battery buildout plan to the Post-April PSIP Plan results in a $443 M reduction in Oahu's NPV of portfolio costs from the original Post-April PSIP Plan. Ascend's optimization of both batteries and renewables, yielding the Ascend Plan, occasions a $809 M reduction in portfolio costs. On the other hand, the E3 Plan increases NPV portfolio costs by $587 M. The increase in costs relative to the original Post-April PSIP Plan results from the lack of development of flexible thermal generation, which causes the E3 Plan to have the highest production costs out of the four plans examined, and incur a $50 M penalty for its nonfulfillment of resource adequacy standards.

4.5. Maui Results and Optimized Plans

In this subsection, Ascend evaluates the Maui Post-April PSIP Plan with Batteries, and then the Maui Ascend Plan. At the end of this subsection, Ascend compares the two Ascend-developed plans with the original Post-April PSIP Plan and the E3 plan.

4.5.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

The Maui Post-April PSIP Plan with Batteries was created through PowerSimm's optimization of batteries for the original Post-April PSIP Plan. The optimal battery buildout plan is depicted in Figure 32 below.

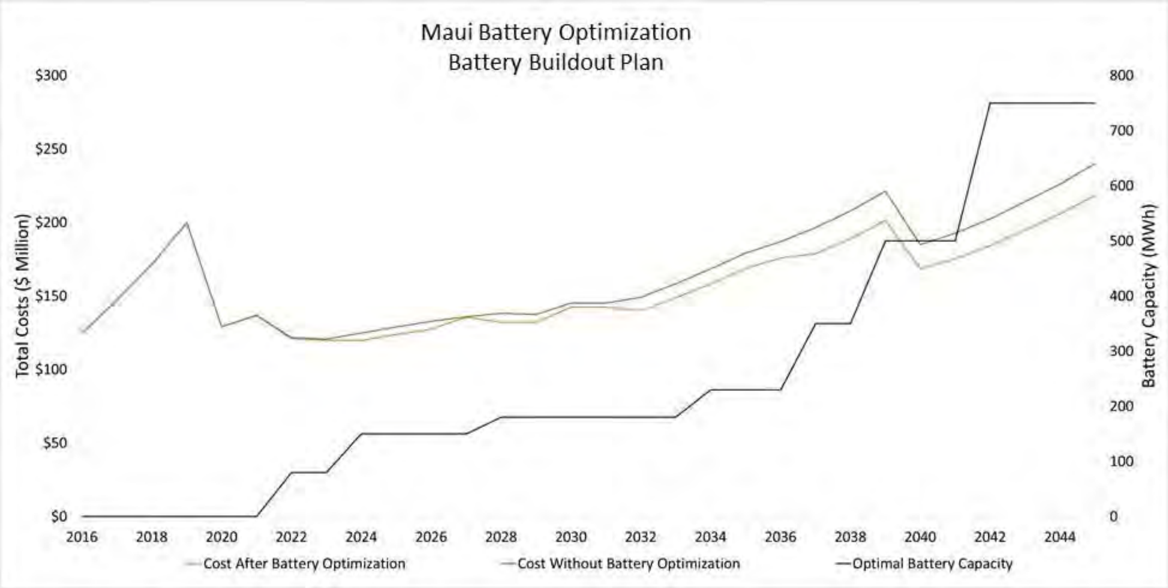


Figure 32: Battery buildout plan for the Maui Post-April PSIP Plan with Batteries.

The black line denotes battery capacity over the years; the green line represents the costs without batteries; and the orange line represents the costs with batteries. It is interesting to note that the production costs drop considerably by 2020. The installation of solar and onshore wind in the Maui Post-April PSIP Plan causes this drop in costs. After the installation of solar and wind, batteries begin to be built out by 2021. Load-shifting batteries begin to provide a notable level of savings by 2032.

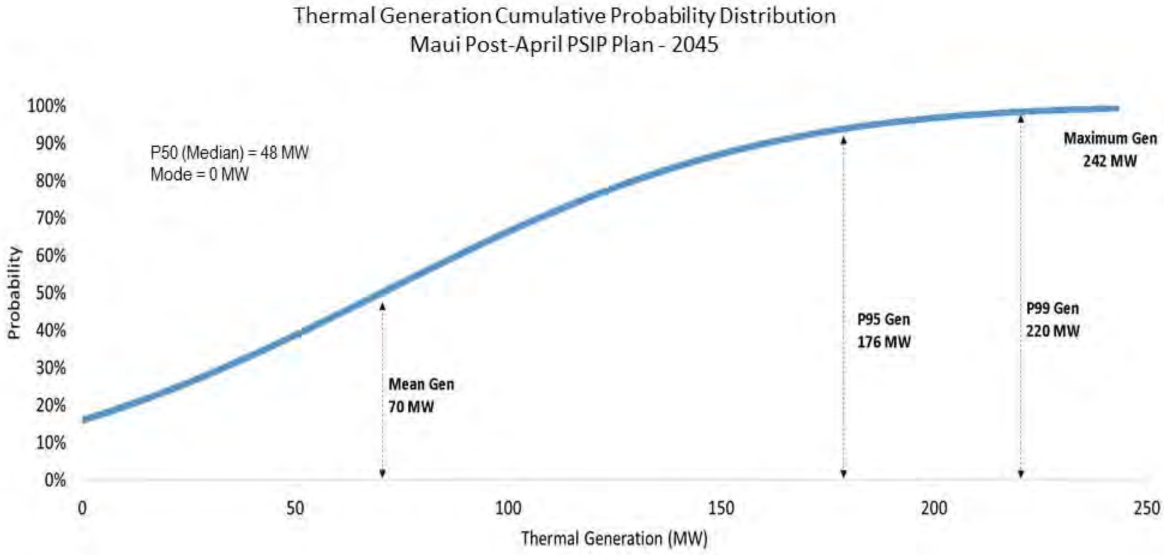


Figure 33: Cumulative probability distribution of thermal generation over distinct weather simulations for the Maui Post-April PSIP Plan (without batteries) in 2045.

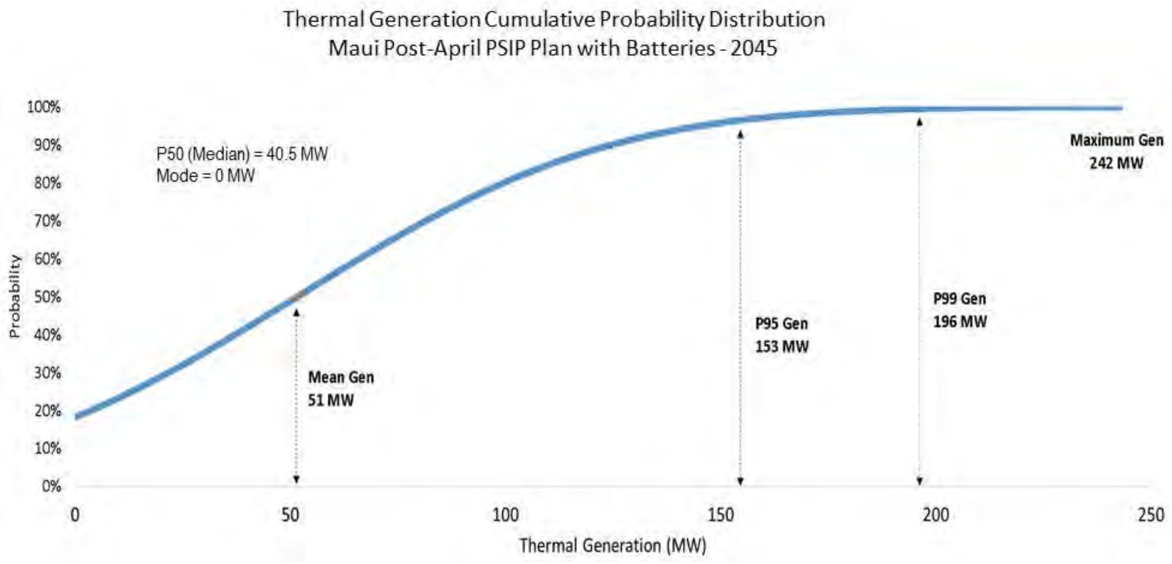


Figure 34: Cumulative probability distribution of thermal generation over distinct weather simulations for the Maui Post-April PSIP Plan with optimized batteries in 2045.

Figure 33 and Figure 34 provide a comparison of the probability distribution of thermal generation in 2045 without batteries and with optimized batteries. Since Maui's energy system is renewable dominant, the mode, or the amount of thermal generation most often required, is 0 MW, with or without batteries. Nevertheless, there are ample instances when thermal generation will be required, as indicated by the average amount of thermal generation for 2045 reaching 70 MW under the Maui Post-April PSIP Plan and 51 MW under the Maui Post-April PSIP Plan with Batteries. Though the average amount of thermal generation decreases by 27% with the addition of optimized batteries, the P95th confidence interval (i.e. the value of which there is 95% chance that the amount of thermal generation required will be less than this value) only decreases by 13% with optimized batteries, and the maximum amount of thermal generation remains at 242 MW, or 124% of average load for the year, for both of the plans. Thus battery additions lessen the need for thermal generation, but the same amount of thermal generation capacity will be needed under both plans to ensure security of supply under the most extreme weather scenarios.

4.5.2. The Optimization of Renewables and Batteries: The Ascend Plan

Ascend jointly optimized solar, wind and batteries to determine the resource plan that would provide the lowest portfolio costs for Maui. Due to the small size of the island, Ascend constrained the optimization of renewables to 100% of its present generation capacity. The results from this co-optimization process of renewables and batteries is presented in Figure 35 below.

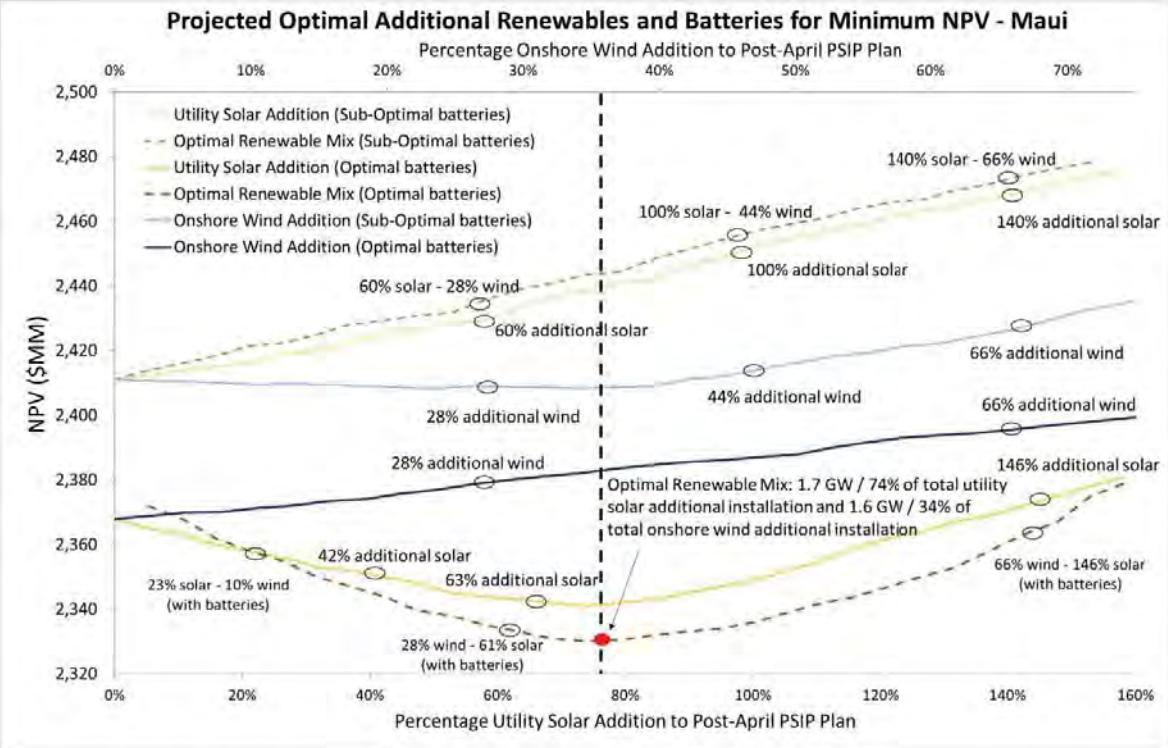


Figure 35: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Maui.

Figure 35 illustrates that the mix of renewables and batteries that provided the lowest NPV costs corresponds to, relative to the original Maui Post-April PSIP Plan, a total additional installation of 74% of utility solar and a total additional installation of 34% of onshore wind. Furthermore, Figure 35 conveys that without optimal levels of batteries additional renewables, instead of providing a reduction in costs, generate an increase in production costs.

Figure 36 shows the battery buildout plan under the Maui Ascend Plan, further highlighting the production cost savings that optimal batteries provide.

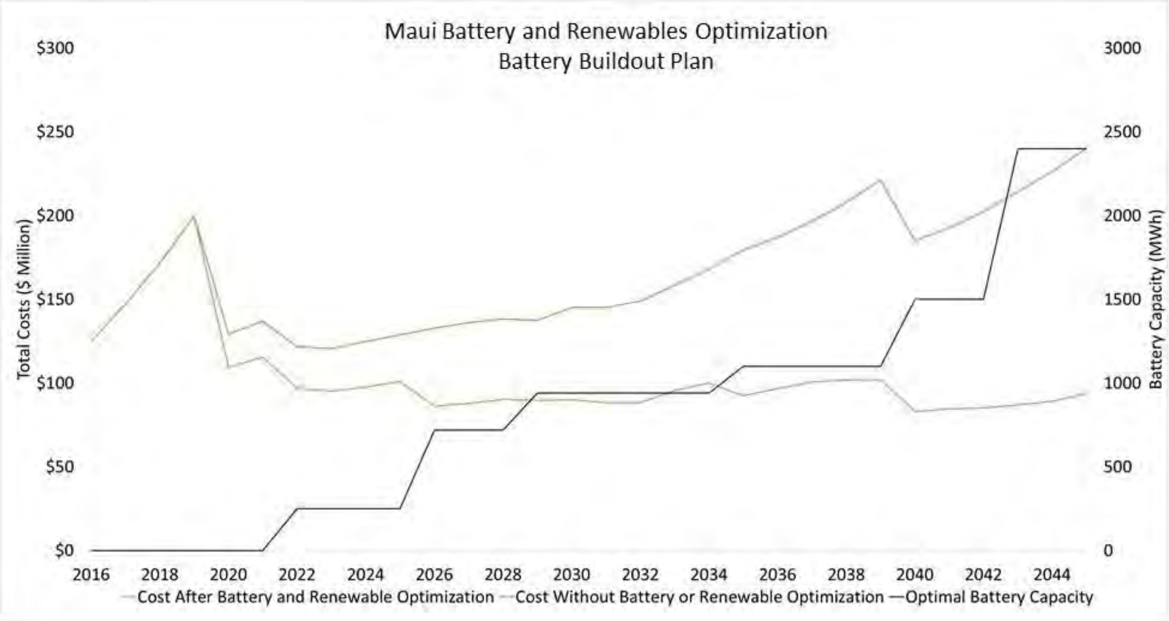


Figure 36: Battery buildout plan for the Maui Ascend Plan.

The battery capacity for the Maui Ascend Plan exceeds the 2045 battery capacity of the Post-April PSIP Plan with batteries by 2026, and by 2045 the former plan's battery capacity is approximately three times higher than the latter. The production cost savings decrease significantly, as the increased renewable capacity makes greater use of the economic potential of batteries.

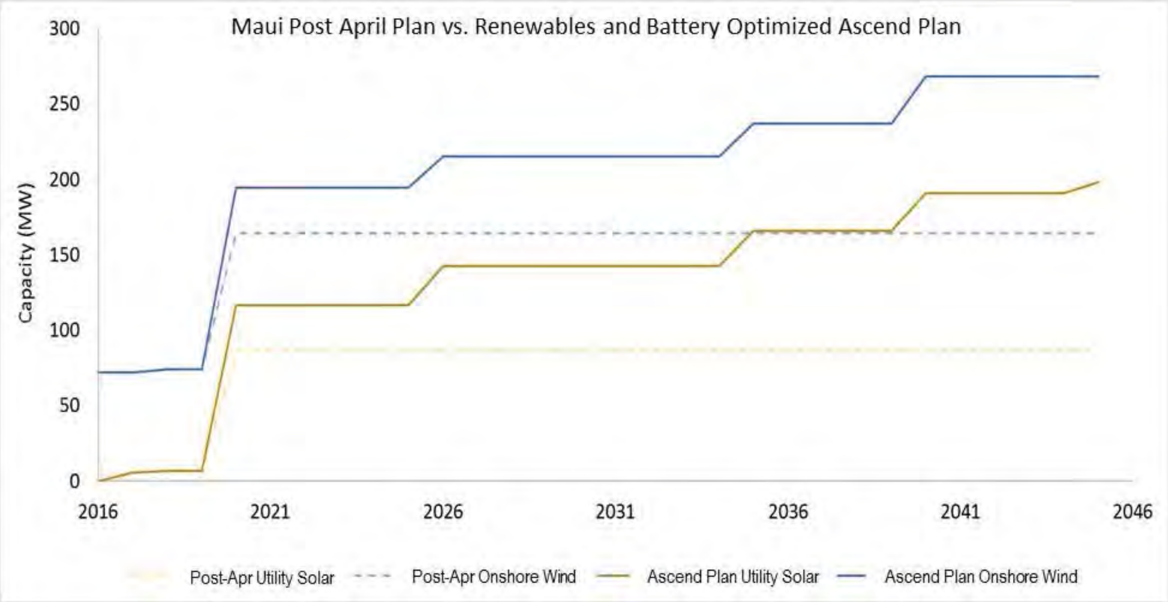
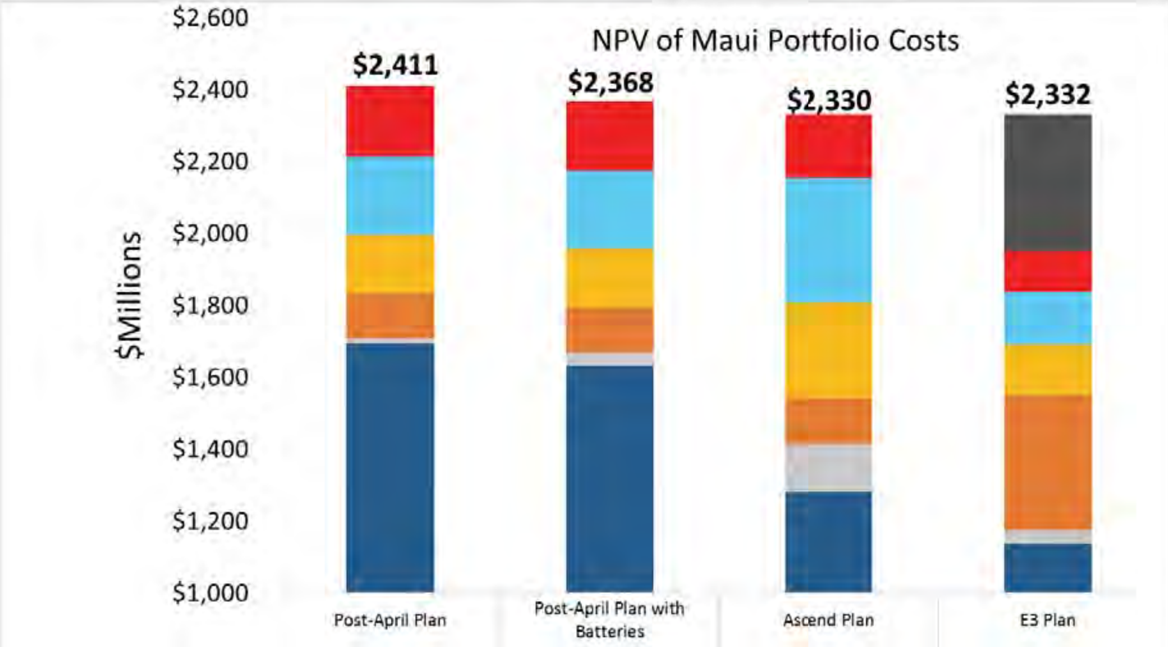


Figure 37: Comparision of renewable capacity additions between the Maui Post-April PSIP Plan and Ascend Plan.

Figure 36 illustrates the capacity additions to the Maui Post-April PSIP Plan that generates the optimal Maui Ascend Plan. The base assumption of the Post-April PSIP Plan consists of one-time additions in 2020 of 80 MW of solar and 90 MW of onshore wind. Ascend's optimized plan introduces an additional 30 MW of solar and wind in 2020, and continues to gradually increase renewable capacities over time. The Maui Ascend Plan does not, as in the case of the Oahu Ascend Plan, increase renewables at the same rate each year. For Maui, seventy-four percent additional solar and 34% additional onshore wind capacities over the entire study timeframe, i.e. from 2017 to 2045, provide the least cost plan, when combined with optimal levels of batteries.



	Post-April Plan	Post-April Plan with Batteries	Ascend Plan	E3 Plan
■ Unserved Energy Cost	$0	$0	$0	$382
■ Risk Premium	$198	$194	$175	$113
■ Capital Costs (Onshore Wind)	$217	$217	$347	$146
■ Capital Costs (Utility Solar)	$162	$162	$267	$139
■ New DGPV	$126	$126	$126	$378
■ Capital Costs (Battery Storage)	$15	$37	$132	$37
■ Production Costs	$1,693	$1,632	$1,282	$1,138

Figure 38: Comparison of NPV of Maui Portfolio costs for the Post-April PSIP Plan, the Post-April PSIP Plan with Batteries, the Ascend Plan, and the E3 Plan.

When the Post-April PSIP Plan is optimized with batteries, Maui portfolio costs decrease by $43 M, while when PowerSimm optimizes the Plan with batteries and renewables, portfolio costs decline by $81 M. The E3 Plan provides dramatically lower NPV costs when penalties for unserved energy are not included. However, due to the E3 Plan's failure to meet resource adequacy standards, as presented in section 4.3.2., PowerSimm adds an additional $382 M in portfolio costs to the plan, bringing the NPV portfolio costs to $2,332 M, or $79 M less than the Post-April PSIP Plan.

4.6. Hawaii Results and Optimized Plans

In this section, Ascend analyzes the Hawaii Post-April PSIP Plan and its optimized counterparts. Due to favorable wind conditions on the Big Island, virtually all of its renewable generation installations are of onshore wind. Thus Hawaii provides an interesting study of the potential savings provided when batteries are coupled with on-shore wind generation. In this subsection Ascend analyzes the Hawaii Post-April PSIP Plan optimized with load-shifting batteries (the Post-April PSIP Plan with Batteries), and then the Hawaii Post-April PSIP Plan optimized with batteries and renewables (the Ascend Plan).

4.6.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

Hawaii's Ascend-optimized battery buildout plan is shown in Figure 39 below. By 2045, the battery capacity is 135 MWh, which is significantly more than the 15 MWh of batteries that the original Hawaii Post-April PSIP Plan proposes. The reduction in costs provided by batteries, however, is minimal. Wind generation and DGPV at the Post-April PSIP Plan's levels do not reap substantial savings from battery utilization.

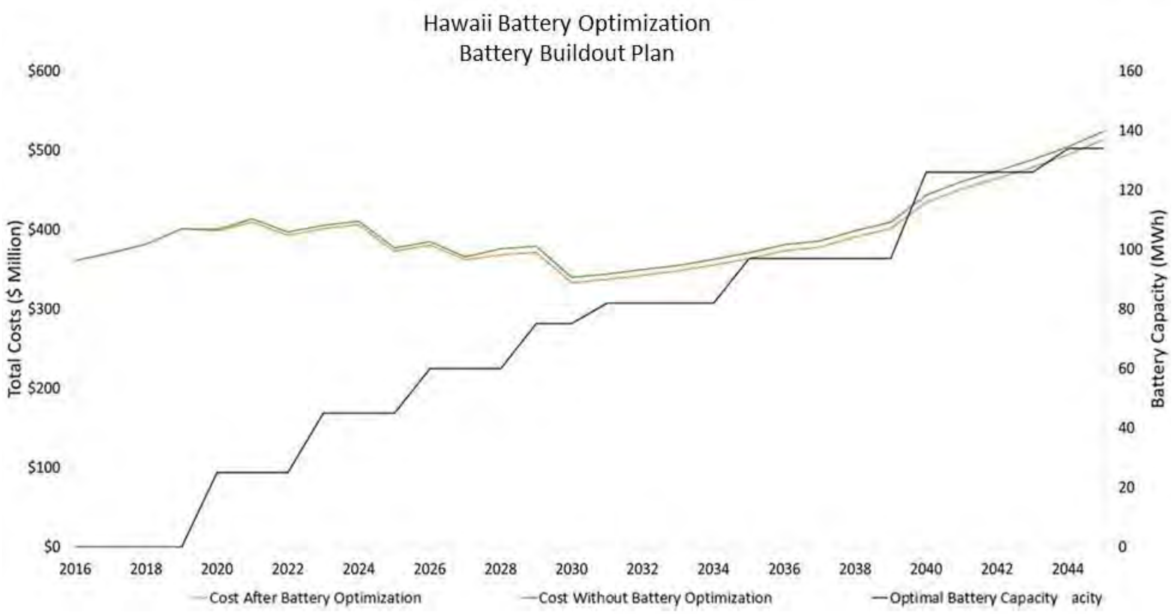


Figure 39: Battery buildout plan for HELCO's Post-April PSIP Plan with Batteries.

Figure 40 and Figure 41 provide a comparison of the cumulative probability distribution of thermal generation requirements for Hawaii in 2045 with and without optimized batteries. For the Post-April PSIP Plan with Batteries, the average thermal generation for 2045 decreases by 37% and the P95th by 15%. However, as in the case of Maui, the maximum thermal generation required to ensure security of supply for the most extreme weather scenarios stays the same between the plans with and without batteries.

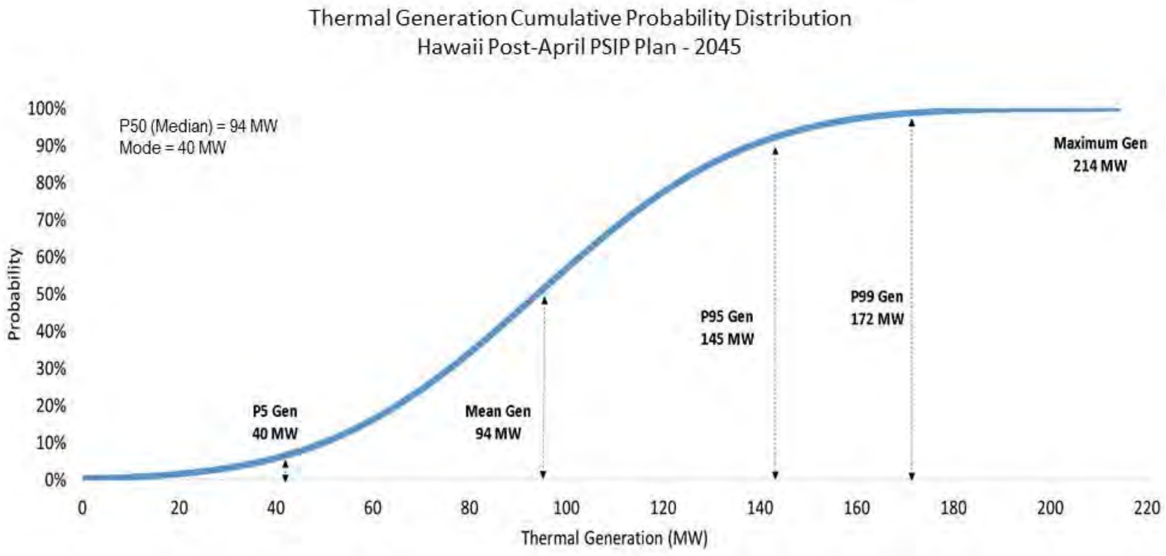


Figure 40: Cumulative probability distribution of thermal generation over distinct weather simulations for HELCO's Post-April PSIP Plan (without batteries) in 2045.

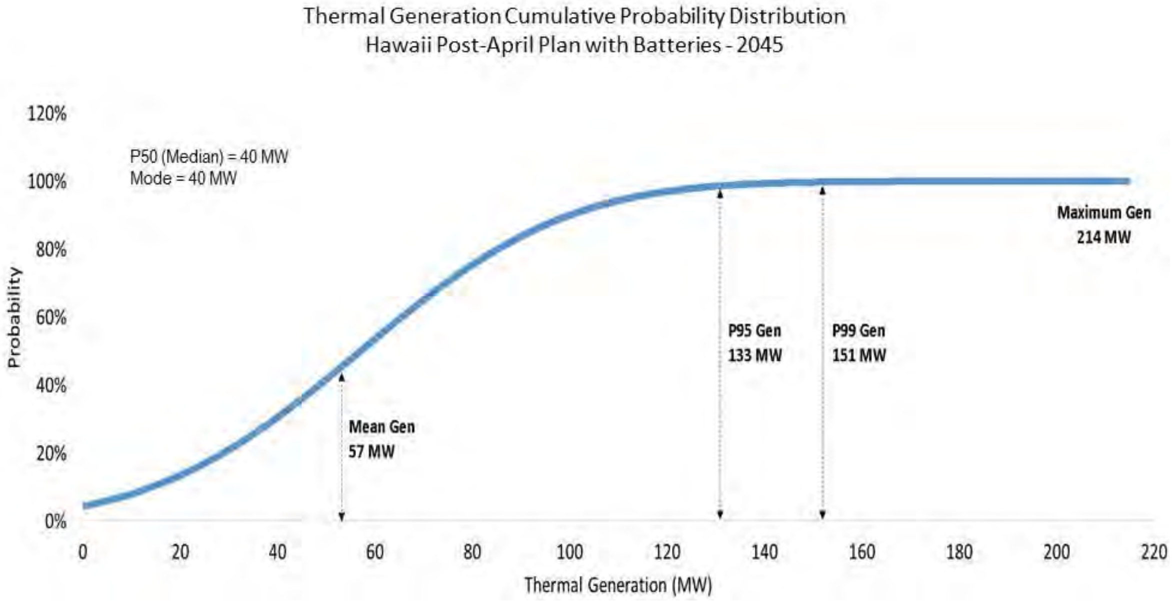


Figure 41: Cumulative probability distribution of thermal generation over distinct weather simulations for HELCO's Post-April PSIP Plan with Batteries in 2045.

4.6.2. The Optimization of Renewables and Batteries: The Ascend Plan

Unlike for the other islands, Ascend's joint optimization of renewables and batteries contains no utility solar additions for Hawaii. The capacity factors on the Big Island are much higher for wind than solar, rendering additional wind without solar the optimal path forward for lowering Hawaii's NPV portfolio costs.

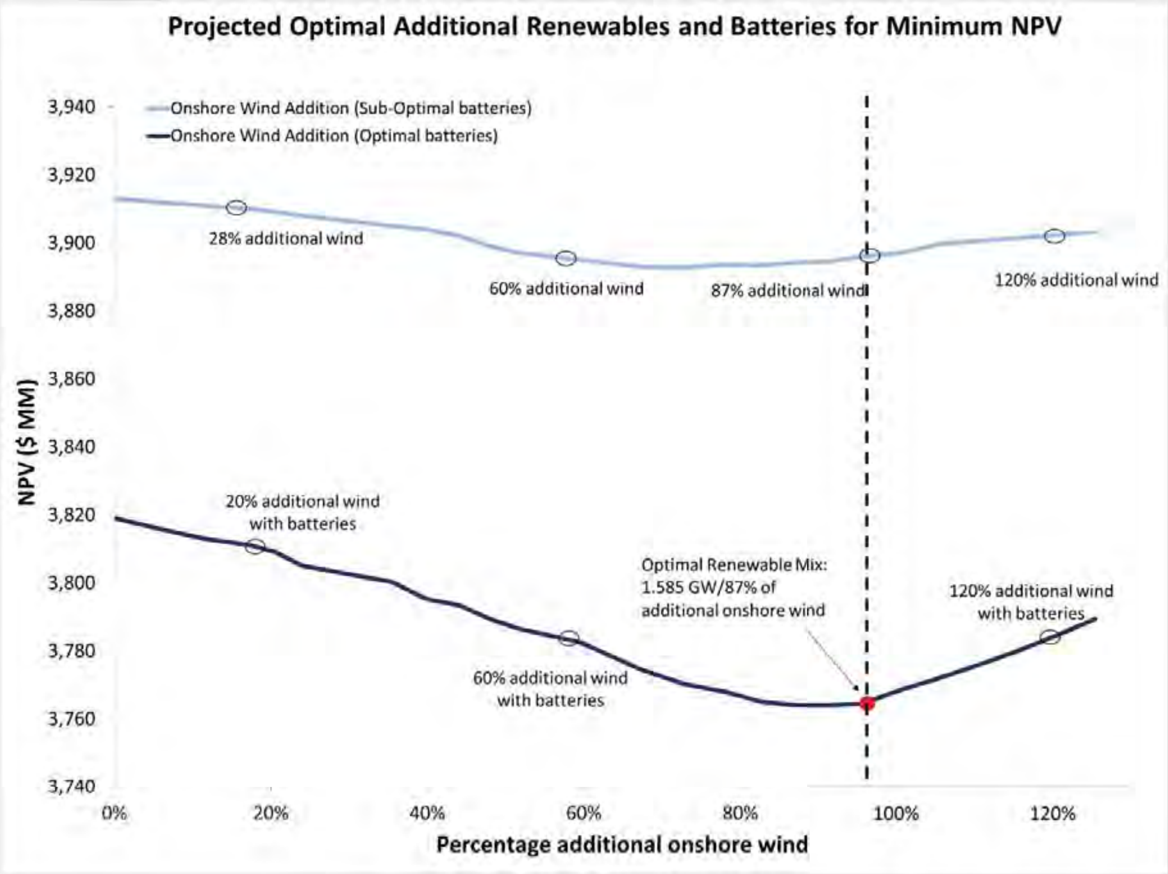


Figure 42: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Maui.

Figure 42 presents that the optimal renewable mix for Hawaii contains 87% MW of additional onshore wind relative to the Hawaii Post-April PSIP Plan, combined with batteries. Figure 42 further presents that there is indeed a portfolio effect between batteries and the additional wind generation, confirming that batteries are essential for minimizing the NPV costs of Hawaii's wind optimization plan.

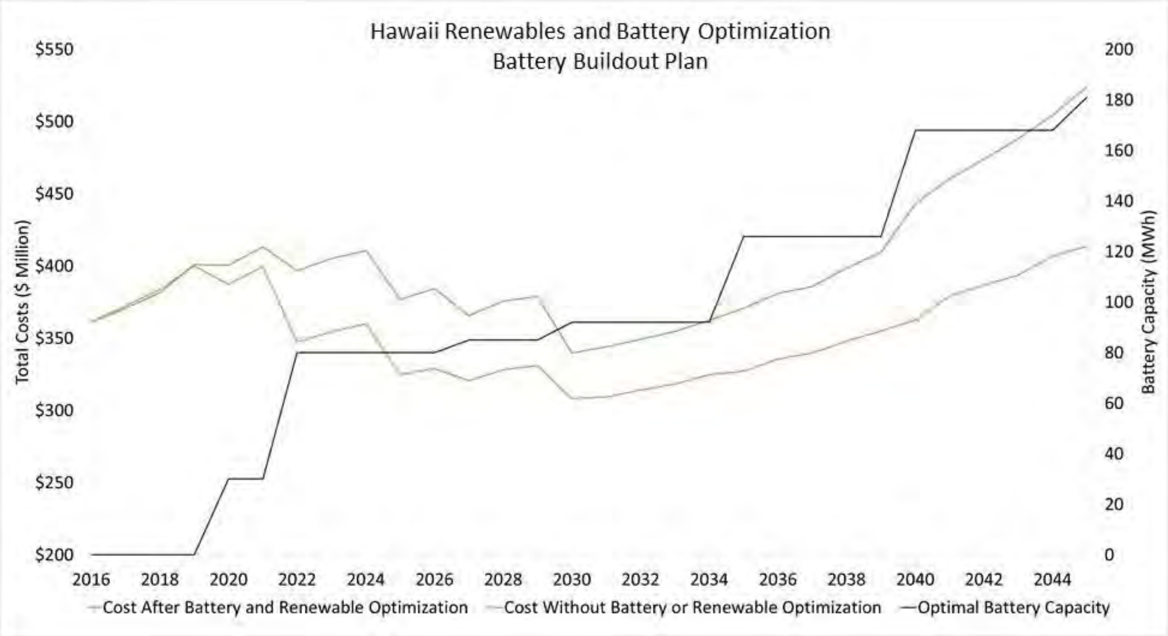


Figure 43: Battery buildout plan for HELCO's Ascend Plan.

Figure 43 presents the optimal levels of batteries for the Hawaii Ascend Plan, further driving home the economic benefits of the wind combined with batteries for Hawaii. The Hawaii Ascend Plan builds out battery capacity to 180 MWh, which is 35 MWh more battery capacity than in the Hawaii Post-April PSIP Plan with Batteries. Due to the absence of solar, the percent increase in battery installations from the Post-April PSIP Plan with Batteries to the Ascend Plan is lower for Hawaii relative to the two other islands. Nevertheless, with the additional battery capacity and wind generation, production costs begin to drop as early as 2022, revealing a pronounced portfolio effect between batteries and wind generation.

Figure 44 compares the difference in renewable capacities between the original Hawaii Post-April PSIP Plan and Ascend's optimization of the plan (the Hawaii Ascend Plan). The Hawaii Post-April PSIP Plan has two 20-MW increases in onshore wind capacity, the first in 2020 and the second in 2030. Unlike the Oahu Ascend Plan, the Hawaii Ascend Plan does not increase the amount of renewable capacity at the same, fixed rate each year. The Hawaii Ascend Plan provides and 87% increase in onshore wind capacity over the entire study timeframe. Compared to the Post-April PSIP Plan, the Ascend Plan has installed an additional 125 MW of onshore wind capacity by 2045.

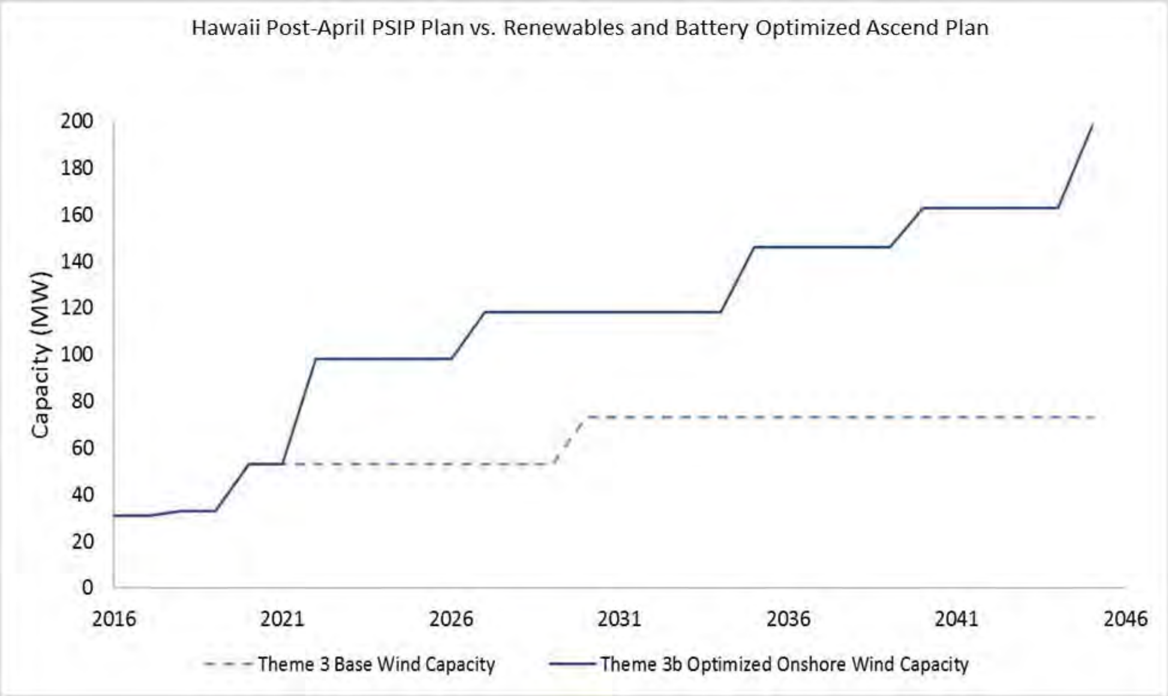
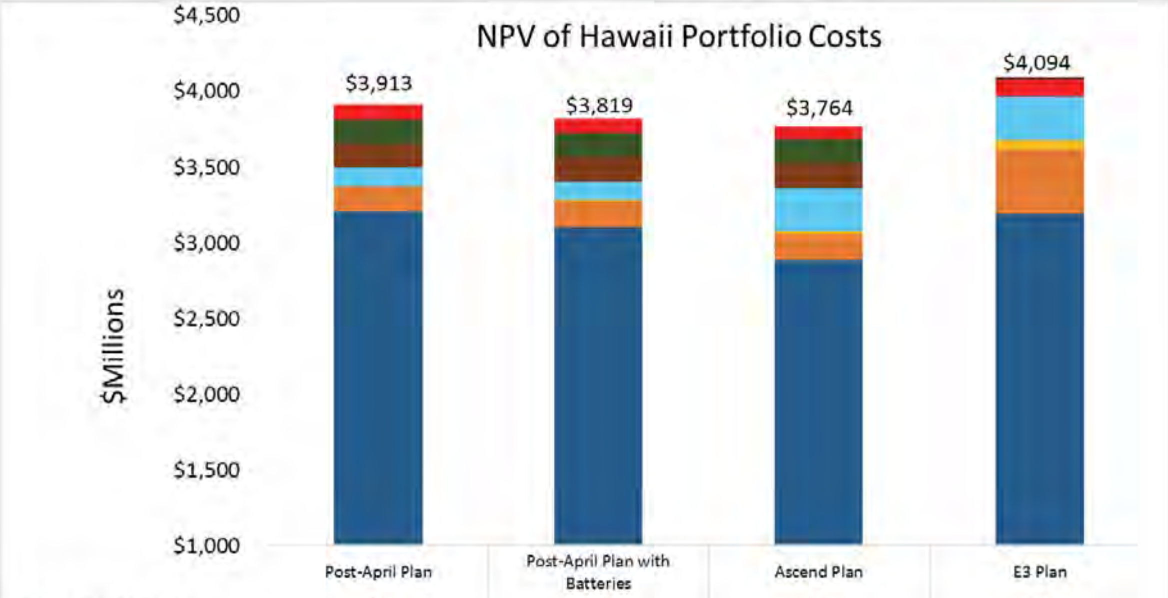


Figure 44: Comparison of renewable capacity additions between HELCO's Post-April PSIP Plan and Ascend Plan.



	Post-April Plan	Post-April Plan with Batteries	Ascend Plan	E3 Plan
■ Unserved Energy Cost	$0	$0	$0	$16
■ Risk Premium	$96	$96	$81	$113
■ Operating Cost (Hydro)	$0	$0	$0	$0
■ Capital Costs (Biomass)	$158	$158	$158	$0
■ Capital Costs (Geothermal)	$166	$166	$166	$0
■ Capital Costs (Onshore Wind)	$116	$116	$285	$288
■ Capital Costs (Battery Storage)	$0	$14	$19	$63
■ New DGPV	$169	$169	$169	$425
■ Production Costs	$3,208	$3,101	$2,886	$3,190

Figure 45: NPV of HELCO portfolio costs for the four HELCO Plans.

When the Post-April PSIP Plan is optimized with batteries, Hawaii portfolio costs decrease by $94 M; when the original is optimized with batteries and renewables, yielding the Ascend Plan, Hawaii portfolio costs fall by 4%, or $149 M. The E3 Plan, however, increases portfolio costs by $181 M.

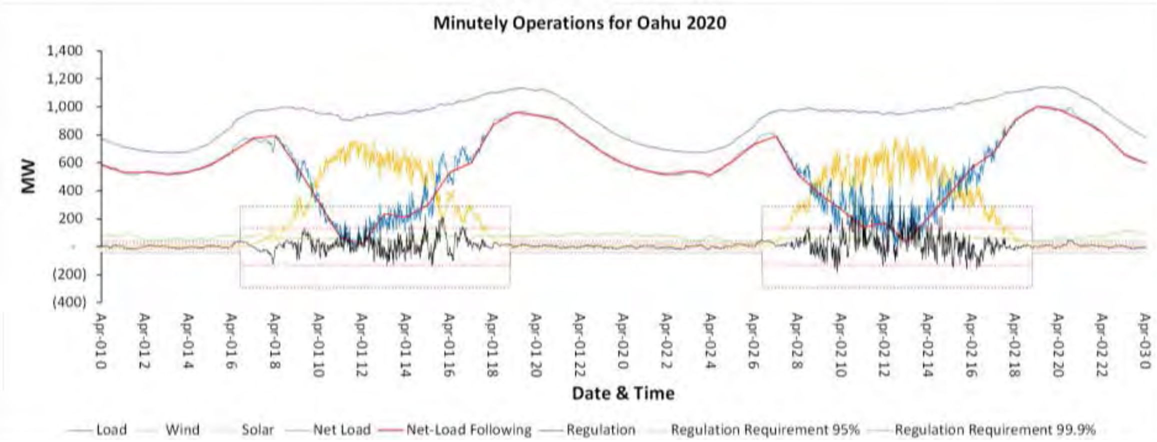
5. Flexibility Analysis

While most planning models assume perfect foresight in dispatch decision-making, such perfect decisions are impossible to make in the real world. On a minutely level, not only is load unpredictable, but with an energy portfolio containing a high level of renewables, generation can be unpredictable as well. Due to the unpredictable nature of both load and generation, batteries are an excellent option for flexible generation because of their very fast and precise charge/discharge capabilities in comparison to thermal generation units with its significant ramp-up times and high costs.

Ascend utilized the PowerSimm module, System Flexibility Software, to help the Companies determine future regulation requirements and the most cost effective ways of meeting those requirements. This section will first discuss Ascend's System Flexibility Software, which calculates the Companies' flexible generation requirements, such as regulation requirements, 15-minute ramps and 1-hour ramps. Then the section will consider PowerSimm's determinations of the most cost-effective way to meet these flexible generation requirements.

5.1. System Flexibility Software

The objective of Ascend's System Flexibility Software is to determine the amount of flexible generation capacity required when planning to integrate intermittent renewable energy sources into an energy system. Flexibility requirements are estimated in terms of (1) regulation requirements necessary to maintain CPS2 scores at 95 and 99.9, (2) ramping requirements at both 15-minute and 1-hour time steps, and 3) changes in ramping direction of net load. Due to the large proportion of solar generation, these requirements are estimated by day-time and night-time requirements. The software determines flexible generation requirements by estimating the variability of historical minutely data for load and renewable generation.



Year	2020	
Day-Time Regulation Requirement 95%	167	MW
Day-Time Regulation Requirement 99.9%	372	MW
Day-Time 15 minute Physical Ramp Up	445	MW
Day-Time 15 Minute Physical Ramp Down	352	MW
Day-Time 1 hour Physical Ramp Up	688	MW
Day-Time 1 hour Physical Ramp Down	475	MW
Night-Time Regulation Requirement 95%	36	MW
Night-Time Regulation Requirement 99.9%	105	MW
Night-Time 15 Minute Physical Ramp Up	187	MW
Night-Time 15 Minute Physical Ramp Down	37	MW
Night-Time 1 Hour Physical Ramp Up	359	MW
Night-Time 1 Hour Physical Ramp Down	203	MW

Figure 46: Oahu forecasted load, renewable generation and regulation for April 15th and 16th, 2020, with accompanying chart.

Figure 46 shows the central results provided by System Flexibility Analysis. The upper dark blue line indicates the load, which has relatively little variation, following the pattern of a muted sine wave. The light blue line denotes net load. Net load is calculated by subtracting solar (indicated by the yellow line), wind (indicated by the green line) and must-run thermal generation (not visually indicated in graphic) from system load. One of the aspects of intermittent renewables, especially solar, is significant, rapid fluctuations in generation, which causes parallel fluctuations in net-load, disrupting the originally quiescent sine wave pattern of system load. Thus, volatility in renewable generation by extension renders net load volatile. Regulation (indicated by the black line) is tasked with balancing out these fluctuations at a minutely level. These fluctuations are the difference between net-load following and minutely generation. Net load following, indicated by the red line, is measured as the linear hourly ramps based on the hourly average of net load. The regulation requirement necessary to maintain CPS2 scores at 95 and 99.9 are signified by the red dotted line and blue dotted line respectively. CPS2 scores are a monthly cumulative measure of the area control error (ACE) that measure the divergence between energy supply and load. A large ACE would result in an increase or decrease in system frequency.

The intermittency of renewable generation largely determines the extent of regulation required. The regulation associated with load for 2020 is 167 MW, or approximately 18% of load. However, the higher renewable generation capacity in 2030 increases the amount of regulation to 313 MW, or 34% of load. As mentioned in the previous paragraph, regulation balances out the uneven generation in renewables. The off-peak (night-time) hours in Figure 46 reflects the joint variability in load and wind generation, which yield 18 MW of regulation requirements in 2020. On the other hand, the on-peak hours, when solar generation is active, result in a regulation requirement of 167 MW.

Change in Solar Generation (MW)	Regulation Requirement (MW)	Percentage Increase of Regulation Requirement	Max 1-Hour Ramp (MW)	Percentage Increase of Max 1-Hour Ramp
0	167	--	688	--
+20	170	1.7%	691	0.4%
+40	174	4.2%	695	1.0 %
+100	184	10.2%	706	2.6%
+200	202	21.0%	720	5.2%
+300	222	32.9%	741	7.7%

Table 5: Oahu, 2020 – flexible generation requirements with additions of solar capacity.

Change in Onshore Wind Generation (MW)	Regulation Requirement (MW)	Percentage Increase of Regulation Requirement	Max 1-Hour Ramp (MW)	Percentage Increase of Max 1-Hour Ramp
0	167	--	688	--
+20	168	0.6%	687	-0.1%
+40	169	1.1%	686	-0.3 %
+100	171	2.3%	685	-0.4%
+200	176	5.3%	685	-0.4%
+300	181	8.4%	686	-0.3%

Table 6: Oahu, 2020 – flexible generation requirements with additions of onshore wind capacity.

A comparison of Table 5 and Table 6 illustrate the effect of increasing solar and onshore wind capacity on flexible generation requirements. As these results suggest, solar tends to have a more considerable effect on flexible generation requirements than wind. Solar has capacity factors of about 20% with the preponderance of generation in the six hours from 9 am to 3 PM. This concentration of solar generation leads to high ramps and the potential for curtailed energy. Moreover, the high spatial concentration of solar contributes to an even higher increase in regulation requirements per MW of added solar, relative to what is seen on the mainland. Complementing solar with wind mitigates the concentration effect with wind generating relatively uniformly over the day. As Table 6 shows, additional onshore wind capacity has a very limited effect on maximum 1-hour ramps, and even marginally lowers these ramps caused by solar, due to its steadier rates of generation relative to solar. Wind has capacity factors in the state of Hawai'i ranging from 40 to 70%.

Moreover, additional intermittent renewables increase the frequency of changes in the gradient for load following. Figure 47 shows how intermittent renewable generation can cause a sawtooth pattern in the red, net-load following line. In the morning hours of April 1st, 2032, the gradient of the net-load following changes 7 times.

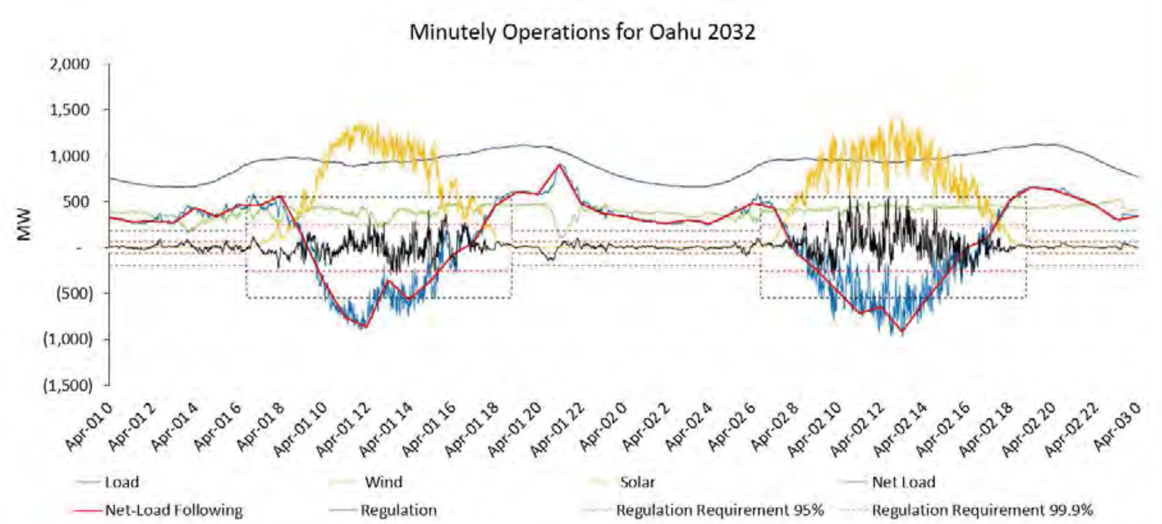


Figure 47: Oahu forecasted load, renewable generation and regulation for April 1st and 2nd, 2032.

5.1.1. Oahu Results

The Daytime Regulation in Table 5 below is the regulation requirement necessary for maintaining a CPS2 score of 95. The Contingent Reserve is the power the energy system should be able to provide in the event of unusual load requirements. It is determined as 6% of peak load for the year. The Max 15-Minute Ramp and 1-Hour Ramp are the largest absolute values from Ramp Up and Ramp Down for their respective time steps, as found in the System Flexibility Software chart. On-Peak Total Flexible Generation is the total power capacity of the ancillary services in peaking conditions for that year. It is determined by summing Day-Time Regulation, Contingent Reserve and the Max 1-Hour Ramp for each year.

Year	Day-Time Regulation (95%) (A)	Contingent Reserve (B)	Max 15- Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	103	74	400	584	761
2018	127	76	420	633	836
2019	134	78	427	650	862
2020	167	78	445	688	933
2021	188	79	456	706	973
2025	262	81	474	738	1081
2030	313	83	502	798	1194
2035	367	91	543	854	1312
2040	400	96	584	924	1420
2045	479	103	642	1,013	1595

Table 7: Oahu renewable integration requirements for flexible generation. All results are unitized in MW.

As Table 5 indicates, Oahu's flexible generation requirements grow considerably with the higher penetration of intermittent renewables over the years. The regulation requirements that Oahu will have to meet more than double in size from 2017 to 2025. Batteries and an updated flexible thermal fleet become crucial and cost-effective assets in meeting these requirements.

Figure 48 provides a visual, side-by-side comparison of renewable generation and flexible generation requirements for the same historic window (April 4th) in 2017 and 2025. The increase in solar generation appears to be the main driver of the increasing flexible generation requirements. In this time period, solar generation capacity (inclusive of DGPV) increases by 152%, from 629 MW to 1,587 MW. Flexible generation requirements in turn increase by 42%, from 761 MW to 1,081 MW.

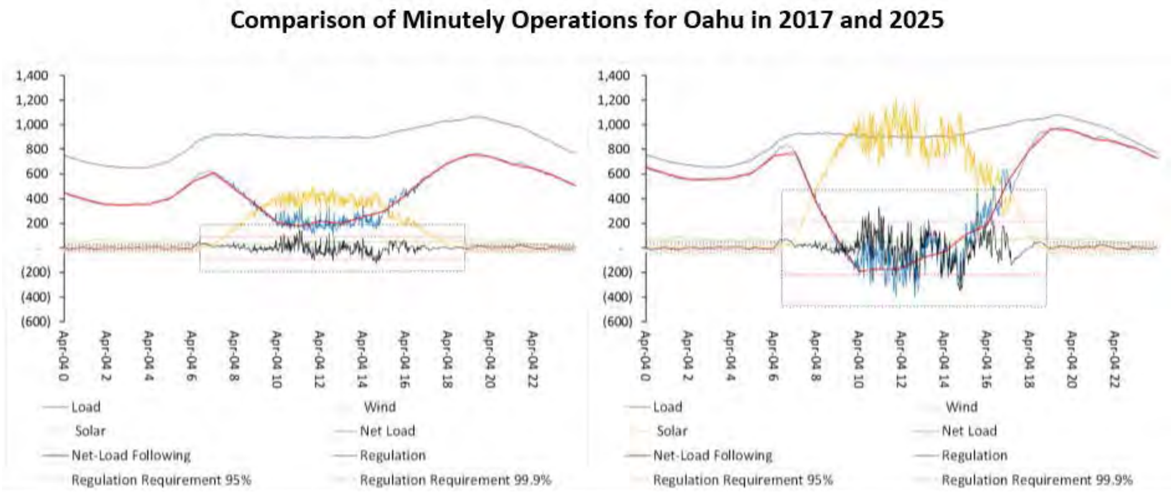


Figure 48: Side-by-Side comparison of renewable generation, load and regulation requirements on April 4th, 2017 and 2025. April 4th, 2017 is depicted on the left and April 4th, 2025 is depicted on the right.

5.1.2. Maui Results

The Maui Post-April PSIP Plan contains an installation of 80 MW of utility solar, and 90 MW of onshore wind in 2020, while in the other years there is no significant installation of renewables. Thus, flexible generation requirements for Maui grow at relatively conservative levels, with the exception of 2020, during which the flexible generation requirements increase by 61%.

Year	Day-Time Regulation (95%)	Day-Time Regulation (99.9%) (A)	Contingent Reserve (B)	Max 15-Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	38	76	12	88	111	199
2018	39	77	12	88	112	201
2019	39	79	13	90	113	205
2020	64	129	13	147	188	330
2021	64	129	13	147	188	330
2025	65	130	14	149	189	333
2030	66	132	13	150	191	336
2035	66	133	14	83	192	339
2040	71	142	15	165	215	372
2045	76	153	16	177	238	407

Table 8: Maui - Renewable integration requirements for flexible generation. Unlike for Oahu, On-Peak Total Flexible Generation is calculated using Day-Time Regulation Requirement necessary to maintain a CPS2 score of 99.9, as opposed to 95.

Figure 49 shows the effect of the additional renewable capacity in 2020 by providing a side-by-side comparison of forecasted renewable generation for April 13th, 2019 and 2020. With the additional onshore wind capacity, wind generation provides 50 to 60 MW of power throughout the day, as opposed to the negligible amount of power its provides during 2019. Solar generation levels also increase, peaking at around 200 MW in 2020 compared with 140 MW in 2019. The additional renewable generation causes the net-load to be negative for the day, indicating that there is excess dump energy which batteries can capture.

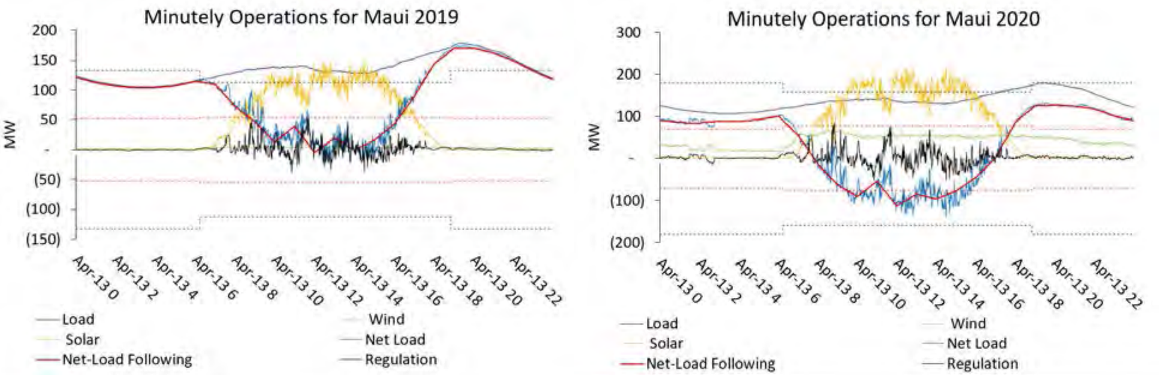


Figure 49: Side-by-side comparison of renewable generation, load and regulation requirements on April 13th, 2029 and 2030.

5.1.3. Hawaii Results

Since the Hawaii Post-April PSIP Plan only installs onshore wind, the percent increase of flexible generation requirements for Hawaii is the lowest of all the islands.

Year	Day-Time Regulation (95%)	Day-Time Regulation (99.9%) (A)	Contingent Reserve (B)	Max 15-Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	18	43	11	63	108	136
2018	19	44	12	63	109	139
2019	19	45	12	64	111	141
2020	20	48	12	62	111	142
2021	21	49	12	63	112	144
2025	21	50	12	63	113	145
2030	22	52	12	60	110	142[4]
2035	23	54	12	64	116	148

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[4] The lower flexible generation requirements in 2030 relative to 2025 is a function of decreasing load.

2040	24	56	13	68	124	158
2045	25	59	14	73	132	172

Table 9: Hawai'i - renewable integration requirements for flexible generation. Unlike for Oahu, On-Peak Total Flexible Generation is calculated using Day-Time Regulation Requirement necessary to maintain a CPS2 score of 99.9, as opposed to 95.

In 2028, Hawaii plans to increase its on-shore wind capacity by 20 MW. Figure 50 offers a comparison of the difference in wind generation between 2029 and 2030.

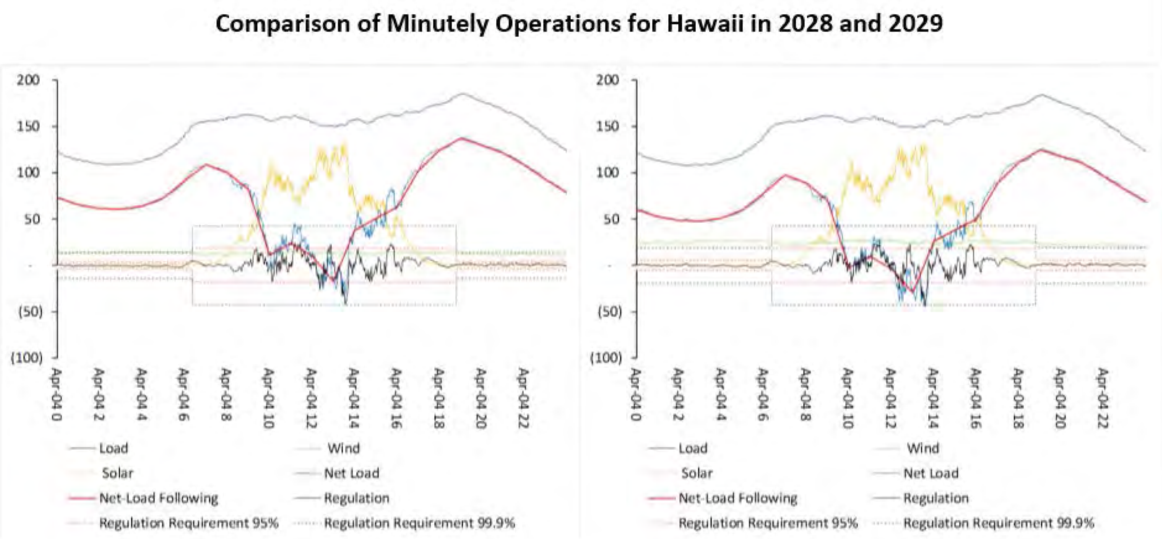


Figure 50: Side-by-side comparison of renewable generation, load and regulation requirements on April 4th, 2027 and 2028. April 4th, 2027 is depicted on the right and April 4th, 2028 is depicted on the left.

Figure 50 indicates that the expansion in wind capacity causes a slight increase in wind generation. This wind expansion does not have a drastic effect on regulation requirements: The regulation requirements from 2029 to 2030 increase by 1 MW.

5.2. Flexible Generation and Batteries

PowerSimm compares thermal generation to batteries and calculates the savings that could be realized through the use of batteries. PowerSimm takes regulation requirements, as determined by System Flexibility Software, as input and determines the most cost-effective way to meet those requirements. PowerSimm calculates not only the savings from using batteries to meet regulation requirements, but it also calculates the savings that can be realized by using flexible batteries to smooth out the sawtooth changes in the net-load gradient induced by renewable generation contributions and daily ramps.

First, this section will define the three different types of batteries presented in this report. Then, this section will discuss the use of batteries to meet regulation requirements. Lastly, this section will discuss the use of flexible batteries.

5.2.1. Three Types of Batteries

This report discusses three different types of batteries:

1) **Regulation batteries** are batteries that are used to meet regulation requirements, discharging and charging on a minutely scale to respond to minor fluctuations in load and generation. Ascend has assumed that regulation batteries have a seven-year lifetime due to their extremely frequent charging/discharging.
2) **Flexible batteries** are used to respond to daily cycles and ramps, discharging and charging on an hourly scale to smooth out changes in the net-load gradient induced by high levels of renewable generation. Ascend assumed that flexible batteries have a twelve-year lifetime due to their less frequent charging/discharging.
3) **Load-shifting batteries**, which have already been discussed in the larger report, are used to absorb excess renewable generation during the day and discharge that energy at night. Thus, load-shifting batteries charge/discharge on a daily scale. Ascend assumed that load-shifting batteries have a fifteen-year lifetime due to their rather infrequent charging/discharging.

While the advantages of load-shifting batteries were discussed in Section 4, this section focuses on the advantages of batteries to furnish flexible regulation and smooth out rapid changes in load following cycles.

5.2.2. Regulation Batteries

The benefits derived from regulation batteries consists of two key elements. The first is the avoided fuel cost that comes from using batteries to provide regulation services. Below, Figure 51 shows thermal units have a declining heat rate as generation increases. Thus, thermal units operate more efficiently as they run closer to full load capacity. When thermal units serve regulation, they operate below their full load capacity, at a heat rate close to the midpoint. Using batteries to provide regulation enables thermal generators to avoid operating at these inefficient levels and save fuel costs. Additionally, batteries have the potential to eliminate costly start-ups from thermal generation. For example, the start-up costs for a combustion turbine of 100 MW is approximately $8,000 dollars. Using batteries to furnish regulation instead can avoid these start-up costs.

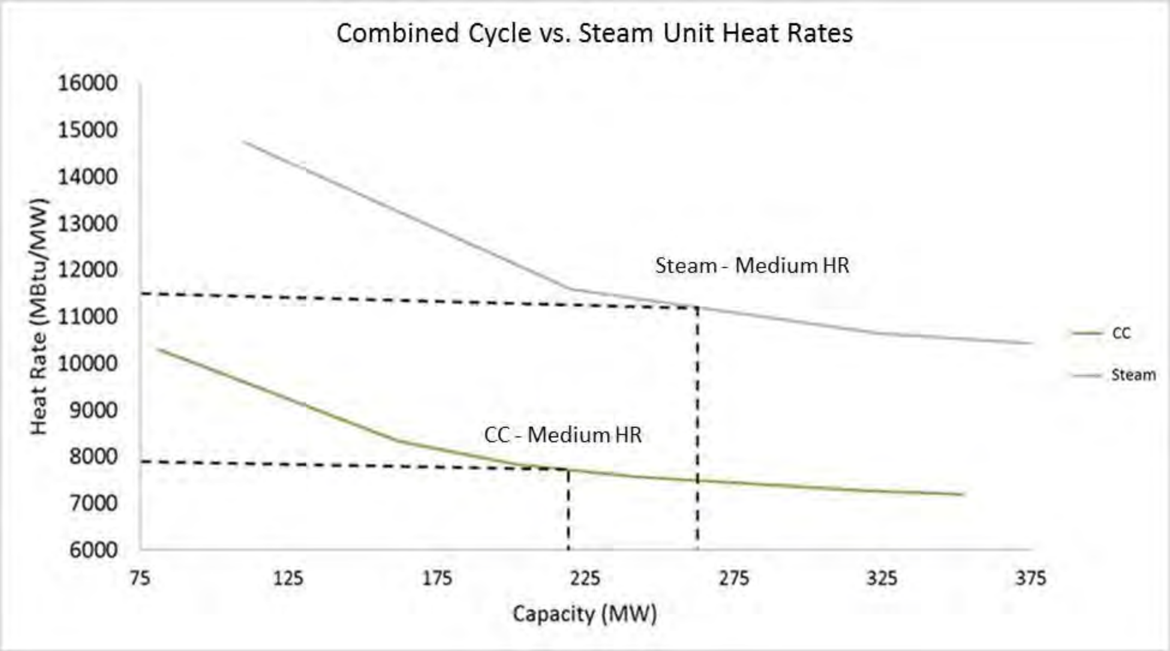


Figure 51: Typical heat-rate curve for combined-cycle and coal generators.

The second element of battery benefits is capacity savings. When batteries furnish regulation, they effectively free up thermal generation that would otherwise be used to serve regulation. This freed up thermal generation can then be diverted to serve capacity, and, in turn, run at more efficient levels.

To compare the supply cost of thermal regulation to the cost of installing regulation batteries for Oahu, the cost-savings calculations consider the levelized cost of regulation batteries. This calculation multiplies the required battery capacity by the effective capital cost of battery installation. This calculation assumes a seven-year lifetime for regulation batteries, and it also assumes that, after seven years, the batteries are worth 50% of the cost of installation at that time. The levelized cost calculation spreads the capital costs of batteries over a seven-year period with an eight percent interest rate. These calculations ultimately show that the supply cost of thermal regulation is consistently much greater than the levelized capital costs for installing regulation batteries. These results are shown below in Table 10 and Figure 52.

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Thermal Fuel Cost - ULSD ($/MMBtu)	$17.81	$19.55	$21.01	$22.25	$23.24	$24.14	$25.17	$26.39	$27.53	$28.61	$29.93	$31.02	$32.55
Regulation Requirements													
On-peak Regulation Requirement (GWh/yr)	392	499	506	640	652	824	838	850	860	873	886	903	916
Off-peak Regulation Requirement (GWh/yr)	80	88	88	88	88	88	88	88	88	88	88	166	166
Regulation Battery Capacity Requirements (MWh)	25	31	32	40	41	52	53	53	54	55	56	57	58
Regulation Costs and Savings													
Thermal Supply Costs to Provide Regulation ($M/yr)	($13)	($17)	($19)	($24)	($26)	($33)	($35)	($37)	($39)	($41)	($44)	($50)	($53)
Levelized Battery Costs - Regulation ($M/yr)	($2)	($2)	($2)	($3)	($3)	($4)	($4)	($3)	($3)	($3)	($3)	($3)	($3)
Savings From Batteries for Regulation ($M/yr)	$11	$15	$16	$21	$23	$29	$31	$34	$36	$38	$41	$47	$50

Table 10: PowerSimm calculation results for regulation battery savings for Oahu.

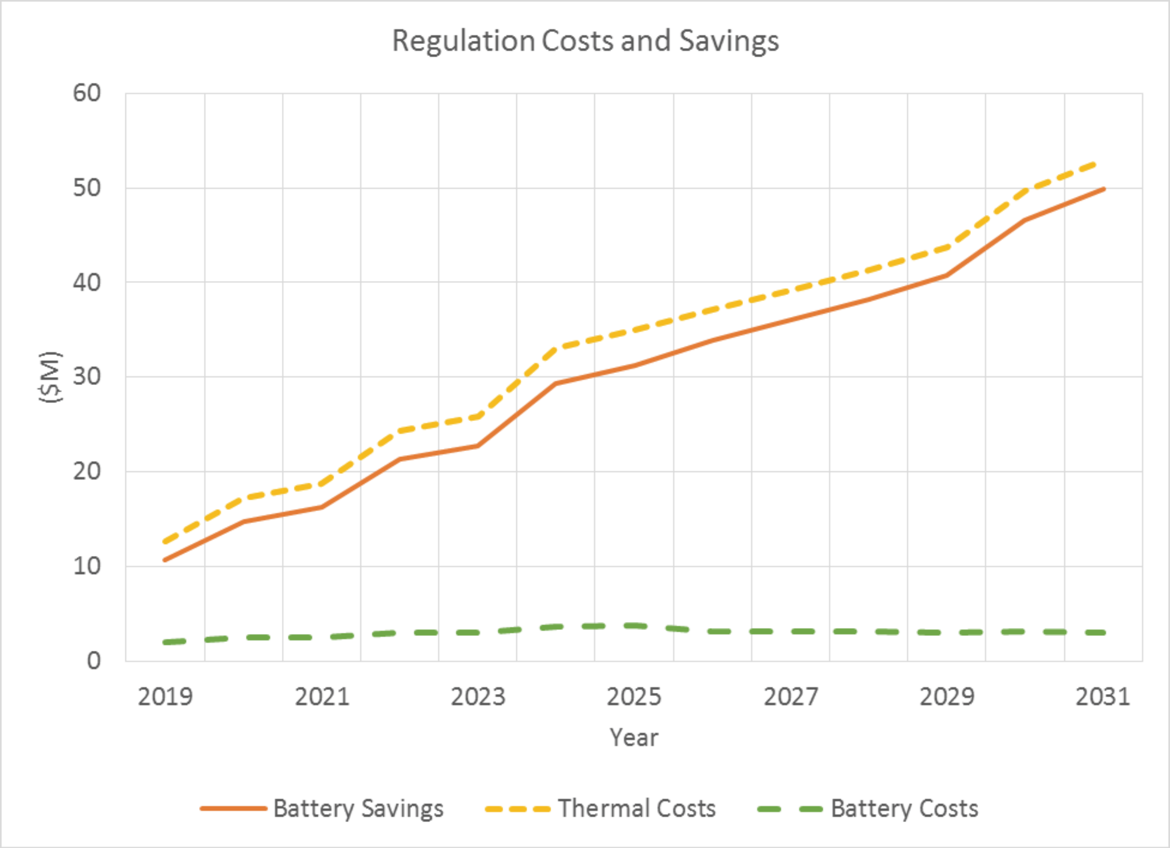


Figure 52: Early savings from using batteries for regulation instead of ULSD thermal generation.

As the above figure shows, regulation batteries offer a prompt reduction in costs upon the first year of their introduction. Over the course of six years, with their capacity approximately doubling, savings from regulation batteries nearly triples.

5.2.3. Flexible Batteries

While regulation batteries provide high-frequency and short-duration charges and discharges to balance the difference between generation and load, flexible batteries serve longer-duration but less frequent cycles. Flexible batteries are usually of a duration of a couple hours and geared toward smoothing out the sawtooth pattern in hourly net load, as well as meeting daily ramps. Flexible batteries provide cost savings by preventing thermal units from running at inefficient heat rates. These savings are further aided through utilizing free dump energy to meet ramps and cycles, instead of producing that energy with thermal generation.

To compare the supply cost of thermal generation to flexible batteries for Oahu, the fuel cost and start-up cost savings of flexible batteries are measured against the capital costs of flexible batteries. The levelized cost of flexible batteries are measured over an assumed life of twelve years with an eight percent interest rate. PowerSimm's calculations show that, starting in the year 2022, flexible batteries provide substantial savings over thermal generation. These results are presented below in Table 11 and Figure 53.

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Thermal Fuel Cost - ULSD ($/MMBtu)	$22.25	$23.24	$24.14	$25.17	$26.39	$27.53	$28.61	$29.93	$31.02	$32.55
Flexible Generation Requirements										
Ramp/Cycle Mgmt Energy Requirement (GWh/yr)	36	40	154	173	196	213	241	255	253	256
Dumped Energy (available for battery storage) (GWh/yr)	67	87	185	214	251	289	331	377	620	663
Battery Capacity Required for Ramp/Cycle Mgmt (MWh)	117	130	508	570	646	702	792	839	832	841
Flexible Generation Costs and Savings										
Thermal Supply Costs to Provide Ramps/Cycle Mgmt ($M/yr)	($2)	($2)	($7)	($9)	($10)	($12)	($14)	($15)	($16)	($16)
Thermal Gen Costs to Produce Dumped Energy ($M/yr)	($7)	($8)	($34)	($39)	($47)	($53)	($62)	($69)	($71)	($75)
Total Thermal Costs (Dump Energy Generation + Ramp/Cycle Mgmt) ($M/yr)	($9)	($10)	($41)	($48)	($57)	($65)	($76)	($84)	($86)	($91)
Levelized Battery Costs - Ramp/Cycle Mgmt ($M/yr)	($5)	($6)	($22)	($25)	($28)	($30)	($34)	($34)	($34)	($34)
Savings From Batteries for Flexible Generation ($M/yr)	$4	$4	$19	$23	$29	$34	$42	$50	$52	$57

Table 11: PowerSimm calculation results for flexible battery savings for Oahu.

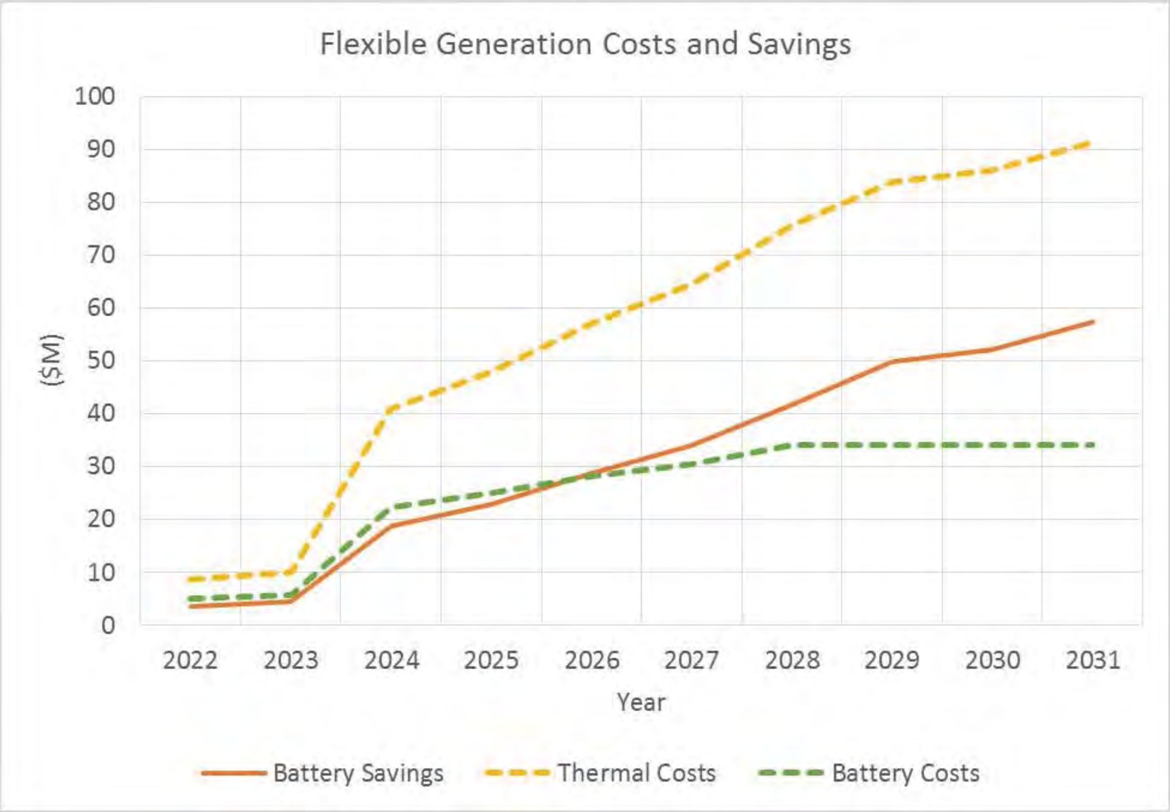


Figure 53: Yearly savings from using batteries for flexible generation instead of ULSD thermal generation.

Figure 15 indicates that, upon an introduction of flexible batteries into the energy system by 2022, flexible batteries provides an immediate reduction in costs, though not to the same extent as regulation batteries. By 9 years after their introduction, increased use of flexible batteries can save $57 million per year.

6. Addendum A: Incorporating Uncertainty in Resource Selection

Since the Companies have an obligation to minimize future costs, it is essential to analyze different energy supply options under many possible future conditions. While traditional modeling approaches utilize "normal" weather years and smooth fuel price trajectories, evaluating energy supply options under this single set of future conditions will almost certainly not reveal the lowest-cost energy supply portfolio over *all* future conditions. PowerSimm stochastically simulates future conditions, including market fuel prices and weather conditions, which drive renewable generation and load. Thus, PowerSimm provides a systematic approach for selecting the lowest-cost energy supply option over a broad range of future conditions. In addition, by simulating a range of future conditions, PowerSimm is able to quantify the risk associated with a particular energy supply option. This section will, first, elucidate the way in which PowerSimm simulations can be utilized to select the best energy supply option over all future conditions, and second, how PowerSimm quantifies the risk associated with a particular energy supply portfolio.

6.1. Stochastic Modeling and Optimal Resource Selection

The PowerSimm capacity expansion logic selects from an array of thermal and renewable assets to provide an evaluation of the optimal mix of these two types of assets. To perform this optimization, the

PowerSimm modeling framework probabilistically envelopes future conditions to aid in optimal resource selection over all future states. Although Ascend could utilize deterministic runs with a single set of future conditions to assess the value of different supply portfolios, such an approach would ignore volatility and uncertainty in crucial variables, such as weather and fuel prices. For example, Figure 54 displays five PowerSimm-simulated Oil price trajectories through 2028. This figure demonstrates how Ascend's PowerSimm software uses multiple simulations of driving variables to probabilistically envelope future conditions.

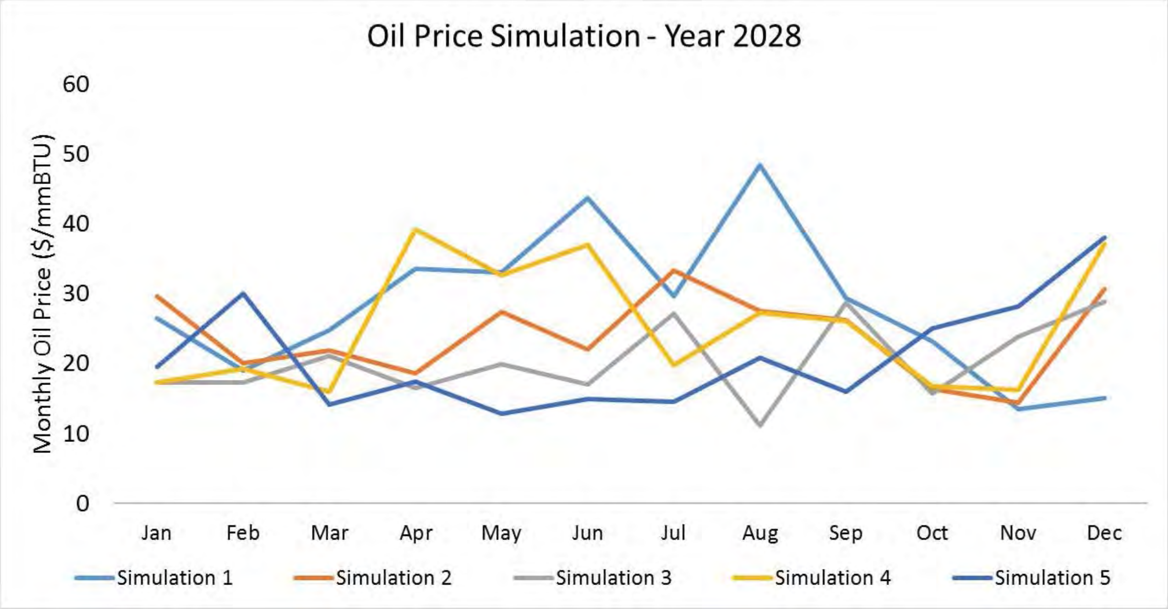


Figure 54: Five PowerSimm simulations of oil prices through 2028.

Thus, Ascend has found that deterministic runs can bias modeling results because of their limited path into the future. Instead, by simulating these variables, Ascend can assess the value of supply portfolios over a broad range of future conditions, and in turn, Ascend can determine which supply portfolios perform the best over all future conditions. Below, Figure 55 illustrates the difference in results between a deterministic run and a stochastic simulation that envelopes a range of future states.

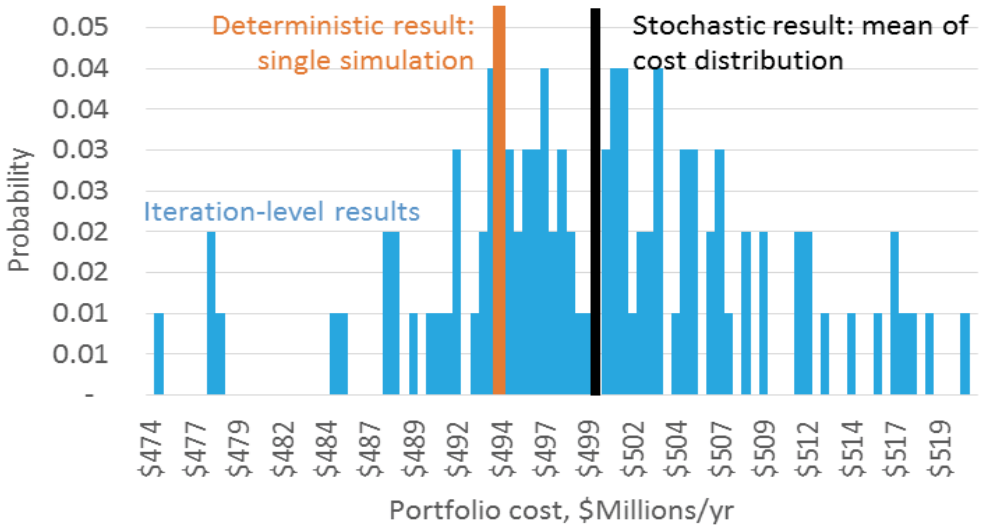


Figure 55: Distribution of iteration-level results used to find stochastic result, versus deterministic result

In Figure 55, the deterministic result yields only one portfolio cost value. However, many stochastic simulations yield a distribution of portfolio cost values with a mean portfolio cost that differs from the deterministic result. The deterministic result is biased by user-determined weather conditions and fuel prices, whereas the stochastically-simulated mean reflects a wide range of future conditions. In this way, the PowerSimm framework can be used to develop unbiased results that take uncertainty into account.

To further illustrate this point using Figure 56, Ascend draws a sporting analogy for resource selection under uncertainty. Selecting the optimal energy portfolio over a deterministic run is equivalent to finding the best swimmer (Michael Phelps), the second deterministic run finds the best cyclist (Chris Froom), and the third deterministic run finds the best runner (Ryan Hall). However, in resource planning, we do not want the best athlete for any individual event, but the best athlete over all events – the best triathlete (Dave Scott). In the same way that the triathlete performs the best over multiple athletic events, the optimal energy portfolio performs the best over a wide range of future conditions. PowerSimm simulates this wide range of future conditions, allowing for the selection of the energy portfolio that performs best over all future conditions.

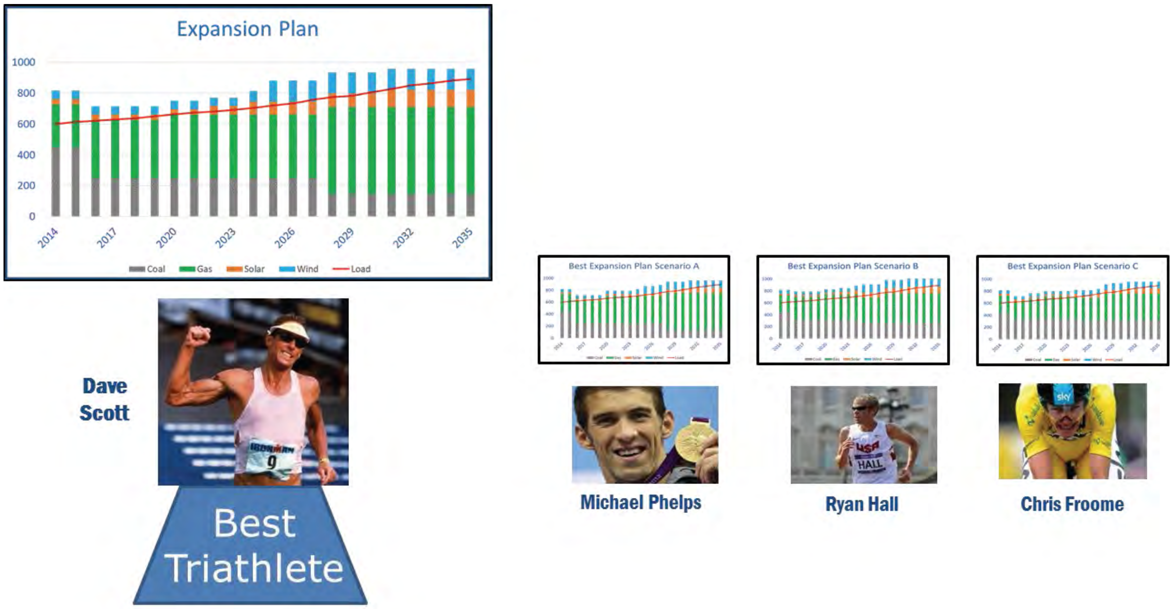


Figure 56: PowerSimm determines which athlete (resource expansion plan) is best over all sporting events (future simulated conditions)

6.2. Calculating Risk Premium

Not only does PowerSimm aid in the selection of the optimal energy portfolio over a wide range of future conditions, but PowerSimm also identifies the risk associated with each energy portfolio option, quantifying this as the “risk premium.” The risk premium is defined as the probability-weighted average of costs above the median. This concept is illustrated below in Figure 57.

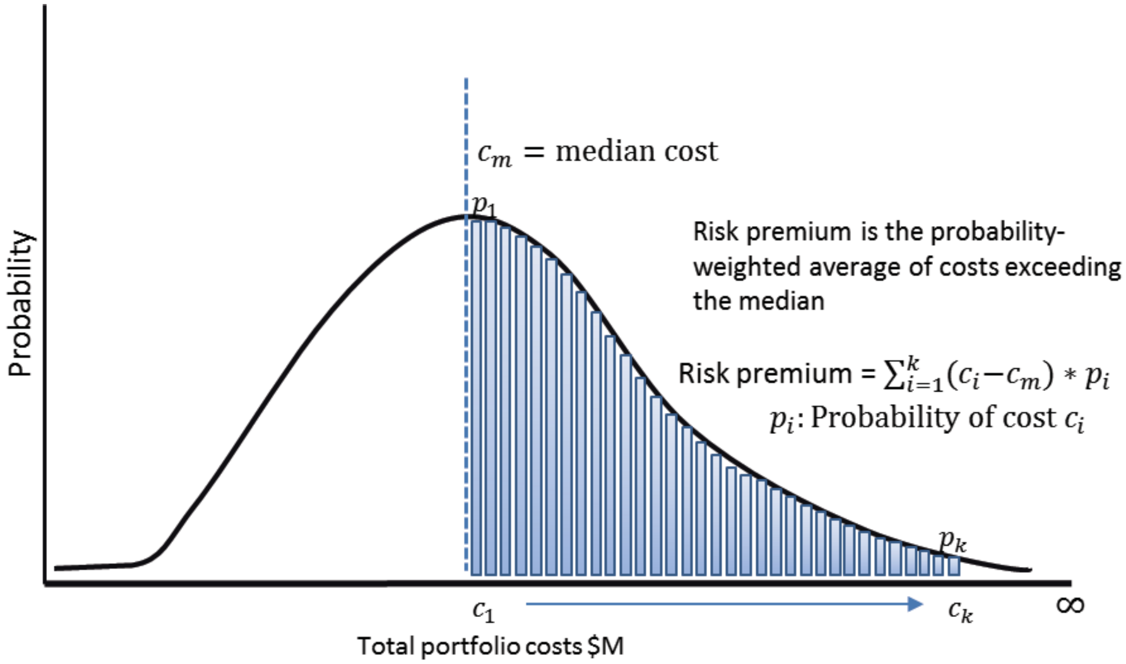


Figure 57: Risk Premium calculation

Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios. After calculating the risk premium, Ascend then adds the risk premium variable to the expected value in order to put all energy portfolio options on the same playing field.

6.3. Simulation Validation Tool

An energy system has to be prepared to not just confront normal weather conditions, but abnormal ones as well. Thus, PowerSimm accounts for a wide variability in possible future weather conditions and its consequent effects on load and generation. The following figures from the Simulation Validation Tool provide insight into the variability covered by PowerSimm.

The validation tool enables the user to scroll through time to view the variation in generation between four distinct weather simulations, as well as the average generation of total weather simulations run by PowerSimm.

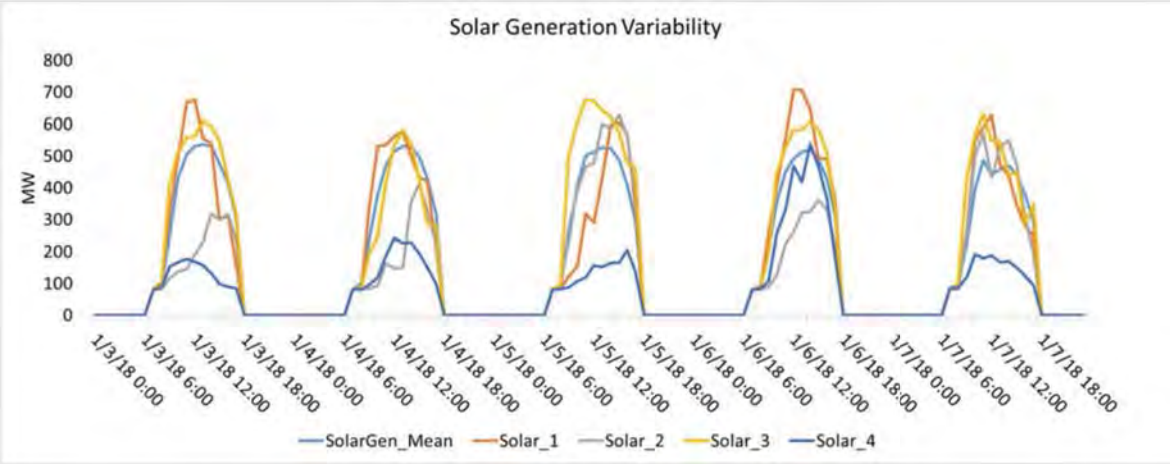


Figure 58: Solar generation over 4 different weather scenario from January 3rd to th 7th, 2018.

Figure 58 presents solar generation over a five-day period. The Solar 4 simulation, indicated by the dark blue line, represents a scenario where solar generation is particularly low. During this period, the mean generation of the 20 distinct simulations of solar generation, represented by the light blue line, can be up to 3 times larger than the generation of the Solar 4 simulation.

Figure 59 provides an example of the variation in solar generation at a later time, in 2045. The dark blue line shows an abnormal weather scenario, over a two-day period, when solar generation is two to three times lower than for the average of the total scenarios.

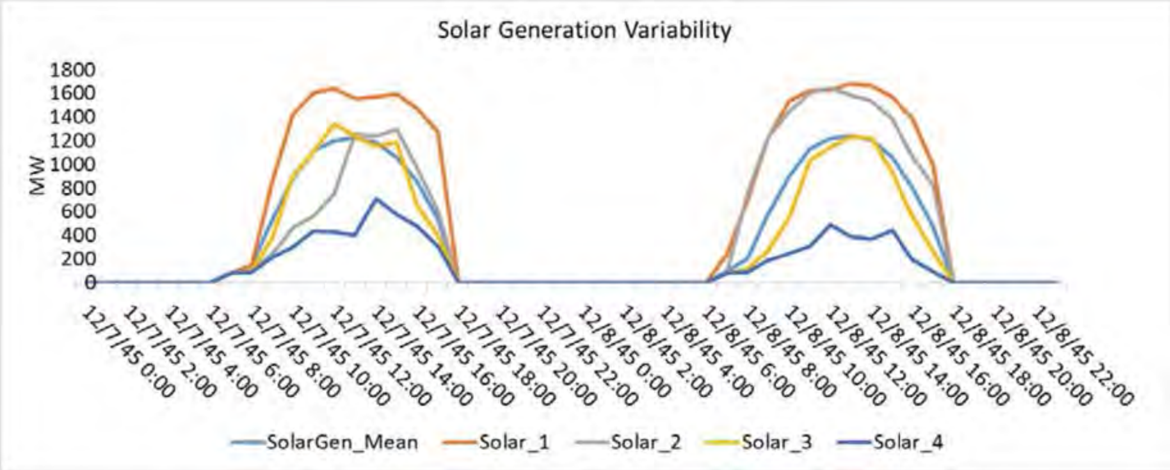


Figure 59: Solar generation over different weather scenarios from December 7th to December 8th, 2045.

Figure 60 presents wind generation for a day in 2029, illustrating that the difference in generation between the 4 distinct weather simulations can vary by up to 500%.

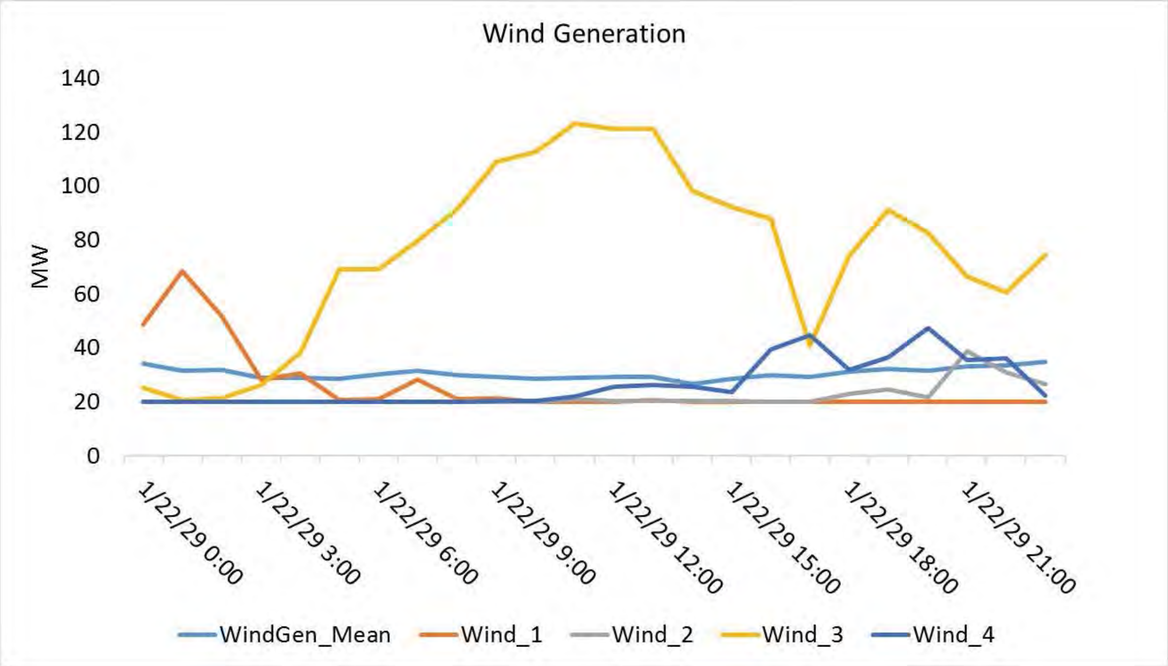


Figure 60: Wind generation over 4 different weather scenarios for January 22nd, 2029.

With the introduction of offshore wind in 2030, some of the variability in wind generation is mitigated, as offshore wind provides a more reliable source of generation than onshore wind. Figure 61 displays this lower variation.

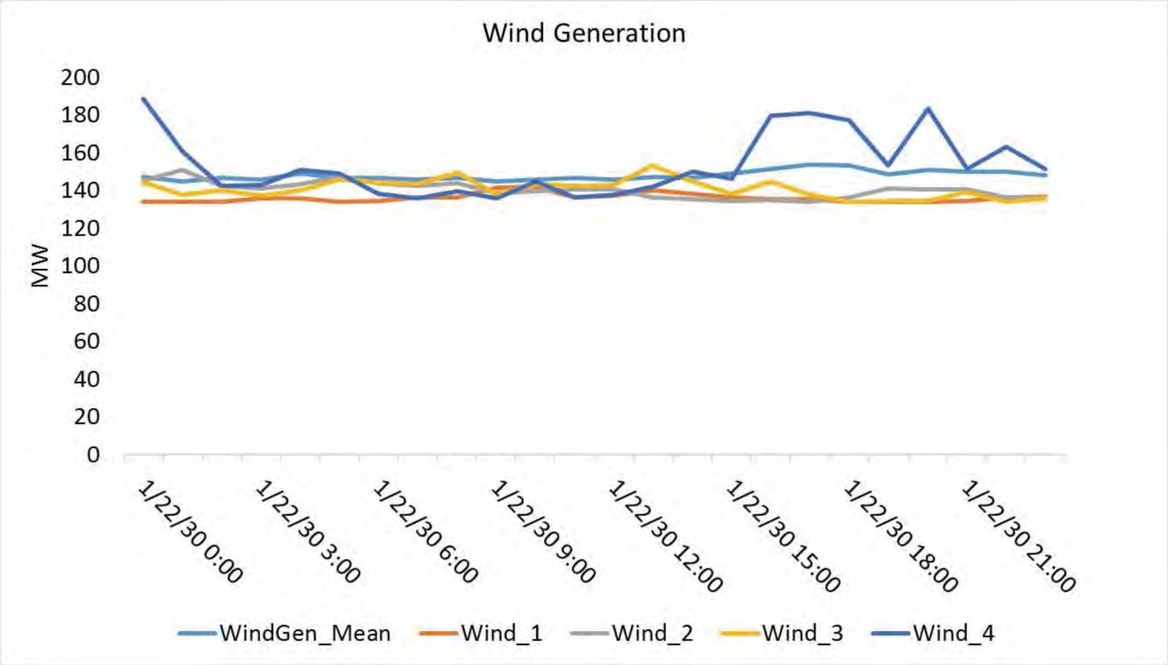


Figure 61: Wind generation over 4 different weather scenarios for January 22nd, 2030.

Thus, as these figures show, PowerSimm incorporates a substantial amount of variability within its inputs. This variability enables PowerSimm to provide results that take into account normal weather scenarios, as well as extreme weather scenarios

7. Addendum B: Model Inputs

With the PowerSimm modeling analysis, Ascend was able to further refine and optimize Oahu's original plans. As part of this process, Ascend utilized new data and added new features to Oahu's themes. Ascend has updated numerous forecasts and used these new forecasts as inputs to the PowerSimm model. This section will discuss updates to fuel forecasts, renewable forecasts, and customer load forecasts.

7.1. Fuel Forecasts

The United States Energy Information Administration (EIA) released a new fuel price forecast which has been included in Ascend's analysis. This forecast included significantly higher oil prices but unchanged LNG prices from the forecast which was used to develop the original themes. Figure 62 shows the forecasted fuel prices used in Ascend's modeling analysis.

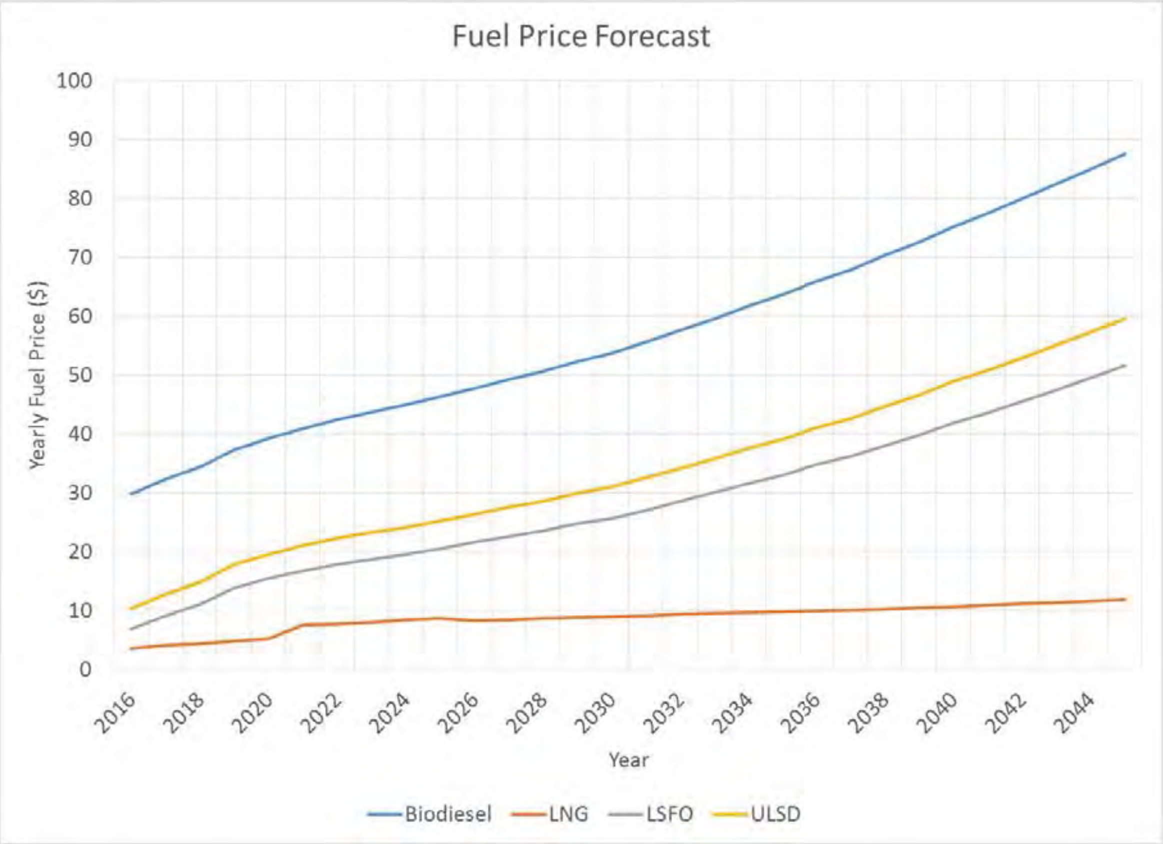


Figure 62: Fuel price forecasts used in PowerSimm modeling

As shown in Figure 62, LNG is the lowest-priced fuel, especially in the later decades of Ascend's analysis. LSFO and ULSD are priced much higher than LNG, and biodiesel is the most expensive fuel of all.

7.2. Renewable Forecasts

In addition to updated fuel forecasts, Hawaiian Electric Companies also provided Ascend with new unitized offshore wind data and new unitized photovoltaic data which were used to create an updated offshore wind forecast and an updated photovoltaic forecast. The new offshore wind data resulted in a forecast with higher offshore wind capacity than previous calculations. Whisker plots for Oahu's solar and wind generation are both shown below.

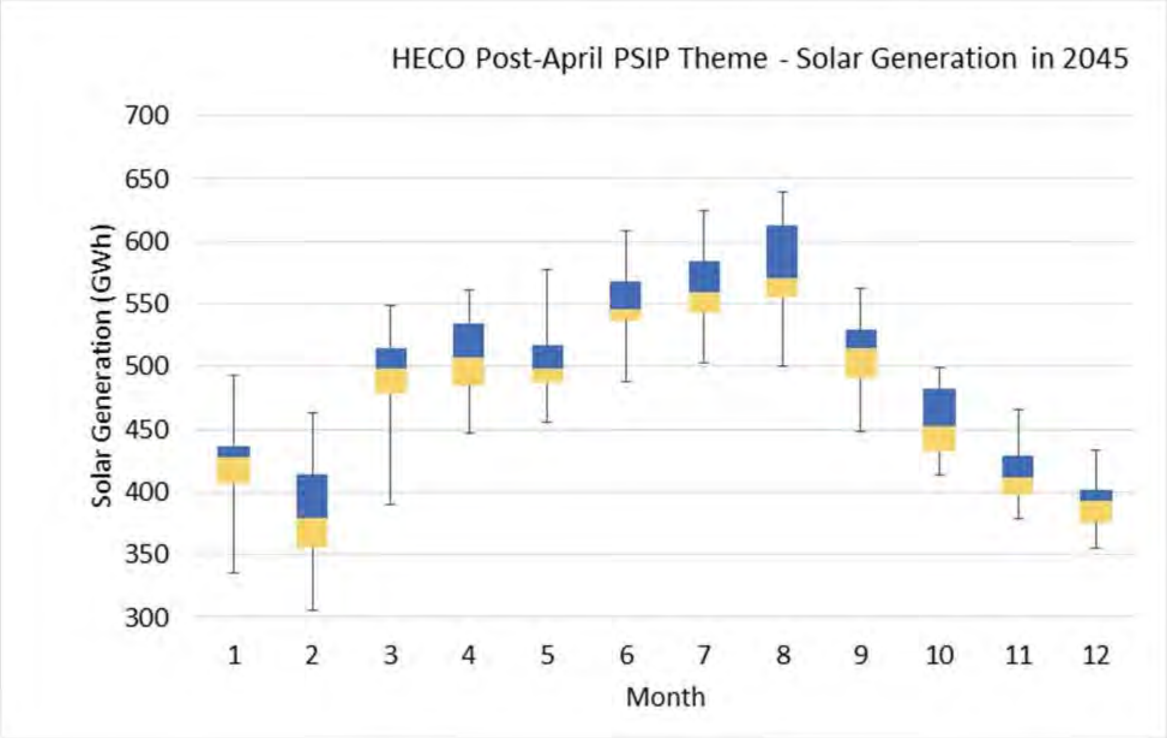


Figure 63: Oahu Theme 1 solar generation in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values.

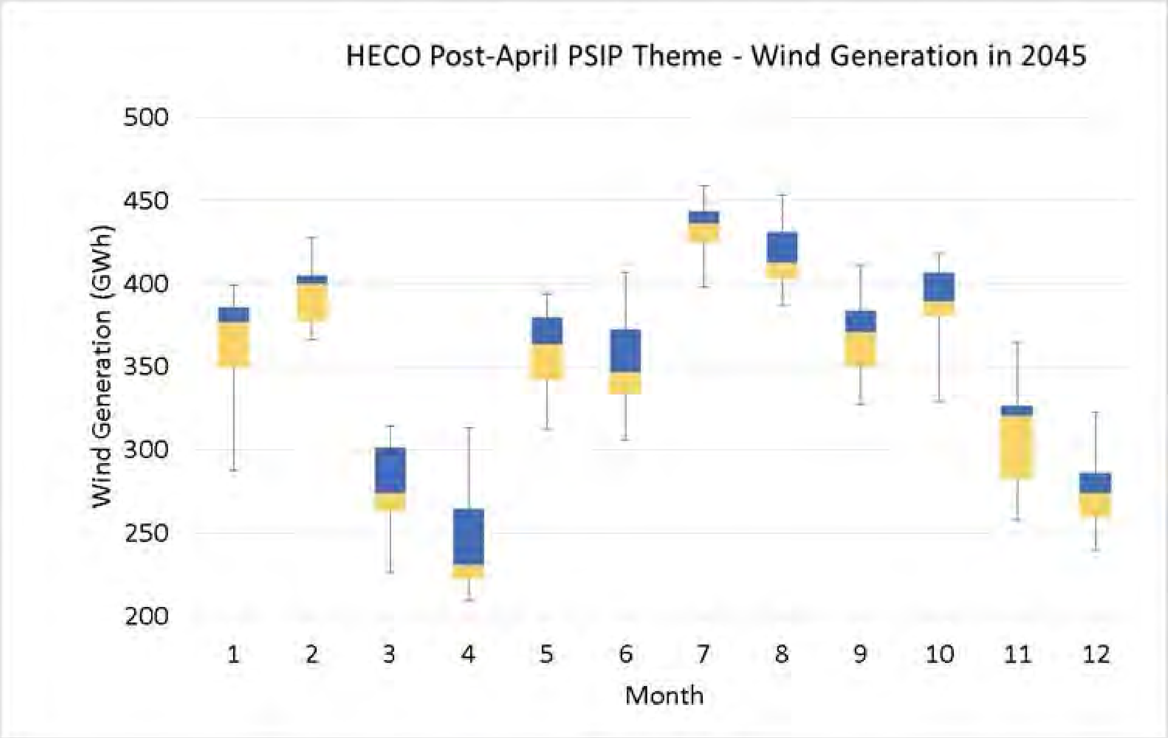


Figure 64: Oahu Theme 1 wind generation in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values. Update

7.3. Customer Load Forecast

With the creation of an updated hourly customer load profile based on the Black & Veatch DR5 forecast, Ascend included this new load profile in its PowerSimm model. The monthly customer load forecast for Oahu in 2045 is shown below in Figure 65.

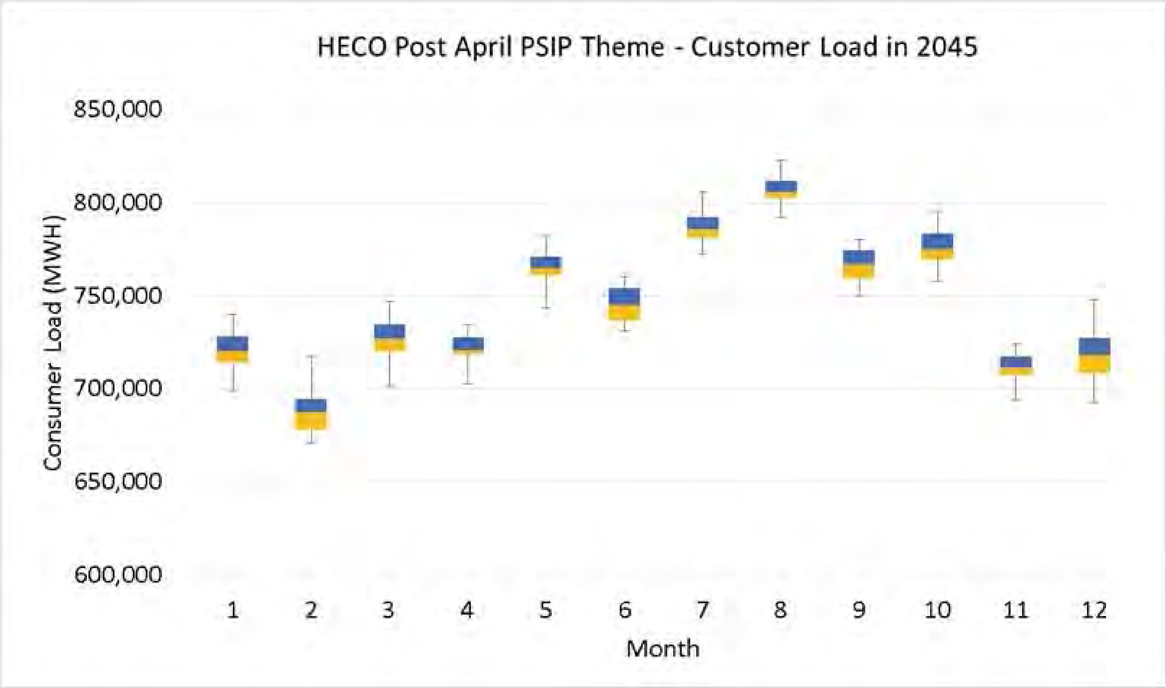


Figure 65: Oahu Theme 1 Black & Veatch DR5 customer load profile in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values.

8. Addendum C: Model Validation

To confirm that Ascend's PowerSimm model is valid, Ascend compared simulated weather, load, and renewable generation data to historical data to ensure that they match. In addition, Ascend also compared generation capacity factors to Oahu's values and simulated prices to forward data. The validation checks are shown in Table 12.

Validation	Completed
Weather	• Benchmark 5th, mean, 95th of historical temperatures
Load	• Hourly load: 5th, mean, 95th • Monthly load: 5th, mean, 95th
Renewables	• Hourly generation: 5th, mean, 95th
Generation Capacity Factors	• Match existing dispatch
Forward Curves	• Match 5th, mean, 95th of option ranges and expectation • Match option quotes of CME contracts

Table 12: Validation checks performed by Ascend to verify model accuracy

Ascend conducted this validation process for Oahu, Maui, and Hawaii, which will be discussed in this subsection in turn. But first the Ascend's Validation Tool will be reviewed.

8.1.1. Oahu Validation

Validation plots for Oahu weather, load, renewable generation, generation capacity factors, and forward curves are shown below. The following plots illustrates the agreement between

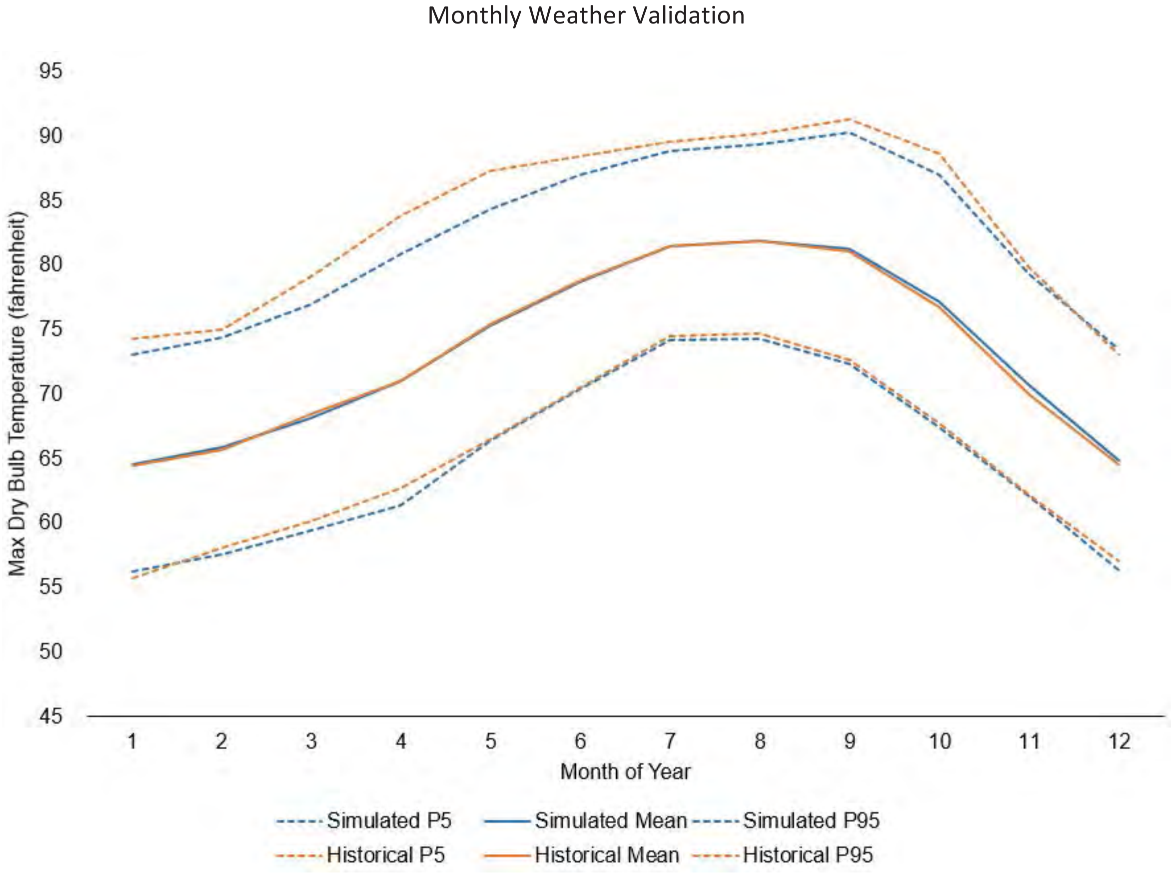


Figure 66: Shows that the historical weather data matches simulated weather data on the monthly level

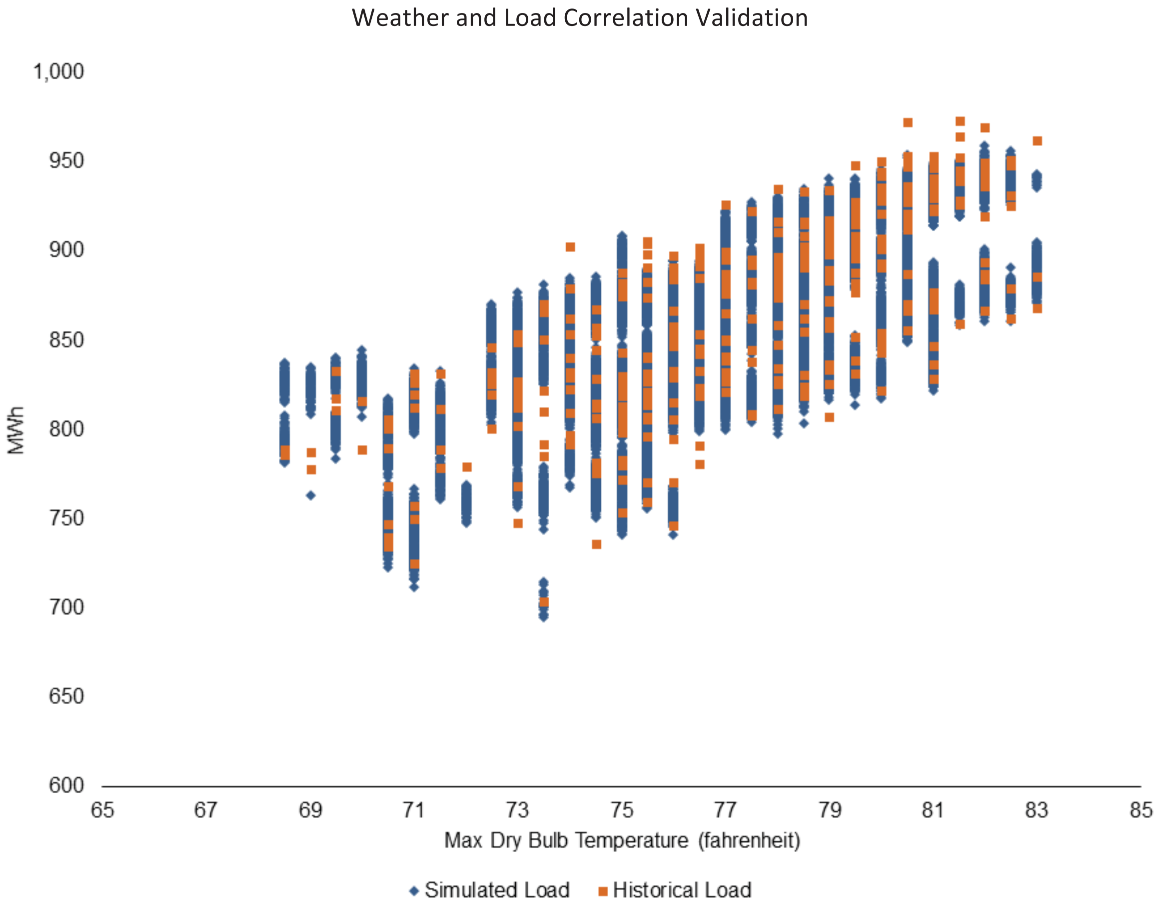


Figure 67: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

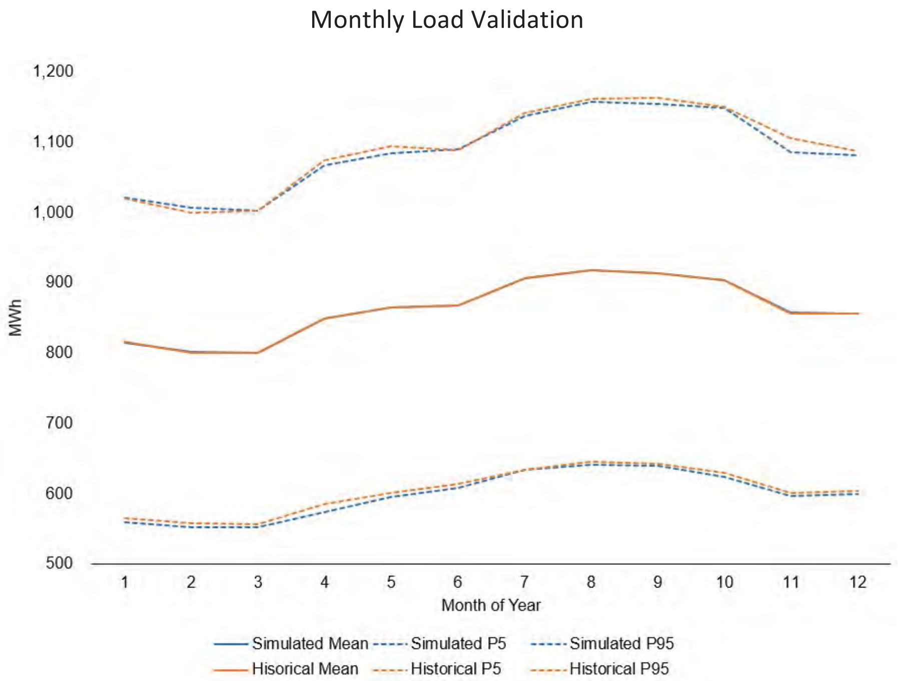


Figure 68: Shows that historical load data matches simulated load data on the monthly level

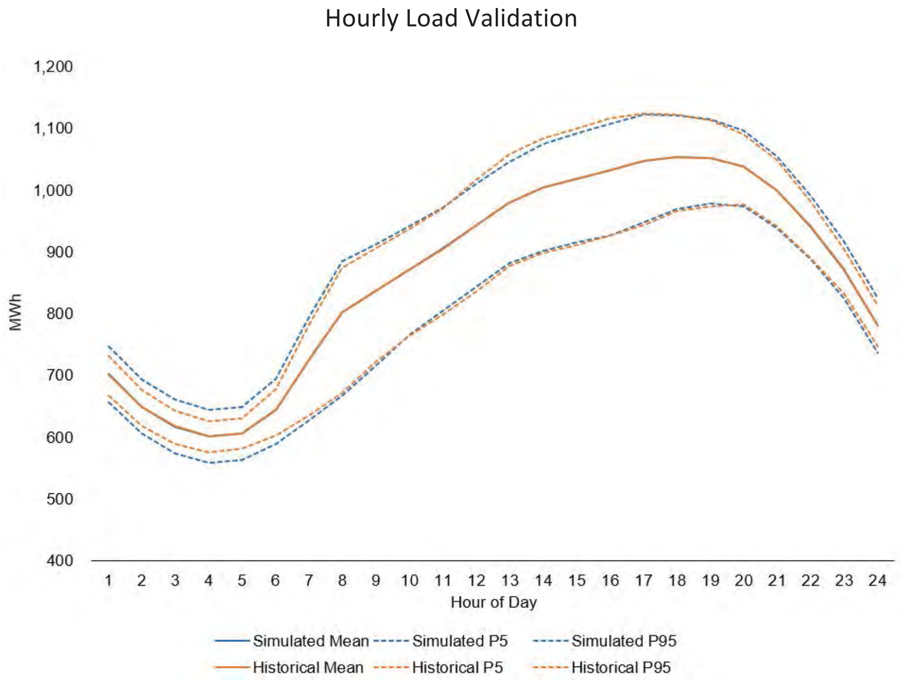


Figure 69: Shows that historical load data matches simulated load data on the hourly level

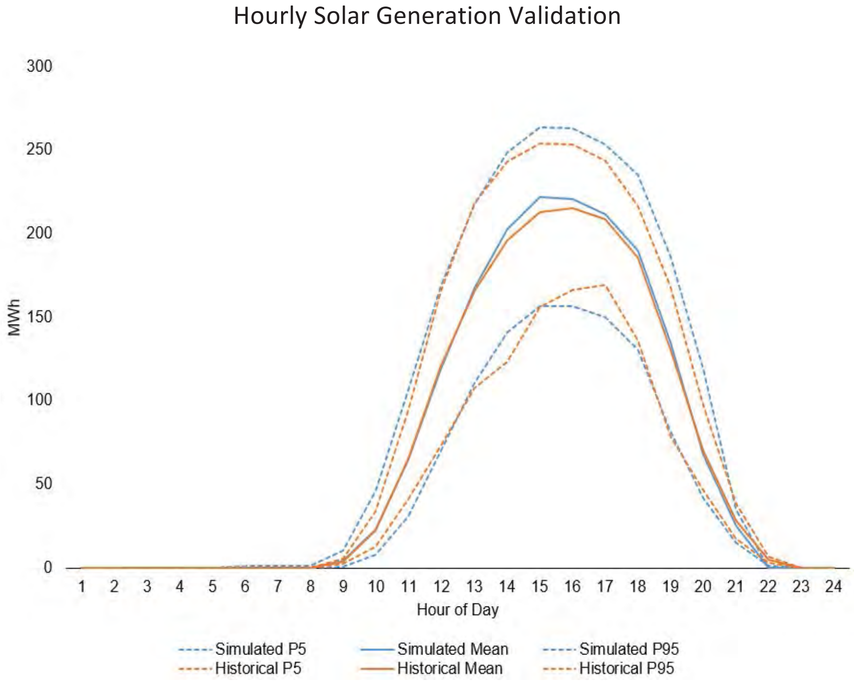


Figure 70: Shows that historical solar generation matches simulated solar generation on the hourly level

Generation Capacity Factor Validation

Generation Station	Ascend Capacity Factors	OAHU Capacity Factors
AES	0.91	0.93
CHEV	0.09	0.13
CIP	0.04	0.02
DSG	0.04	0.04
HIE	1.00	0.97
HP	0.53	0.43
Kahe	0.54	0.46
Kala CC	0.77	0.80
Waiau	0.13	0.17

Table 13: Shows that the Ascend generation capacity factors match the Oahu generation capacity factors

Fuel Price Forecast Validation

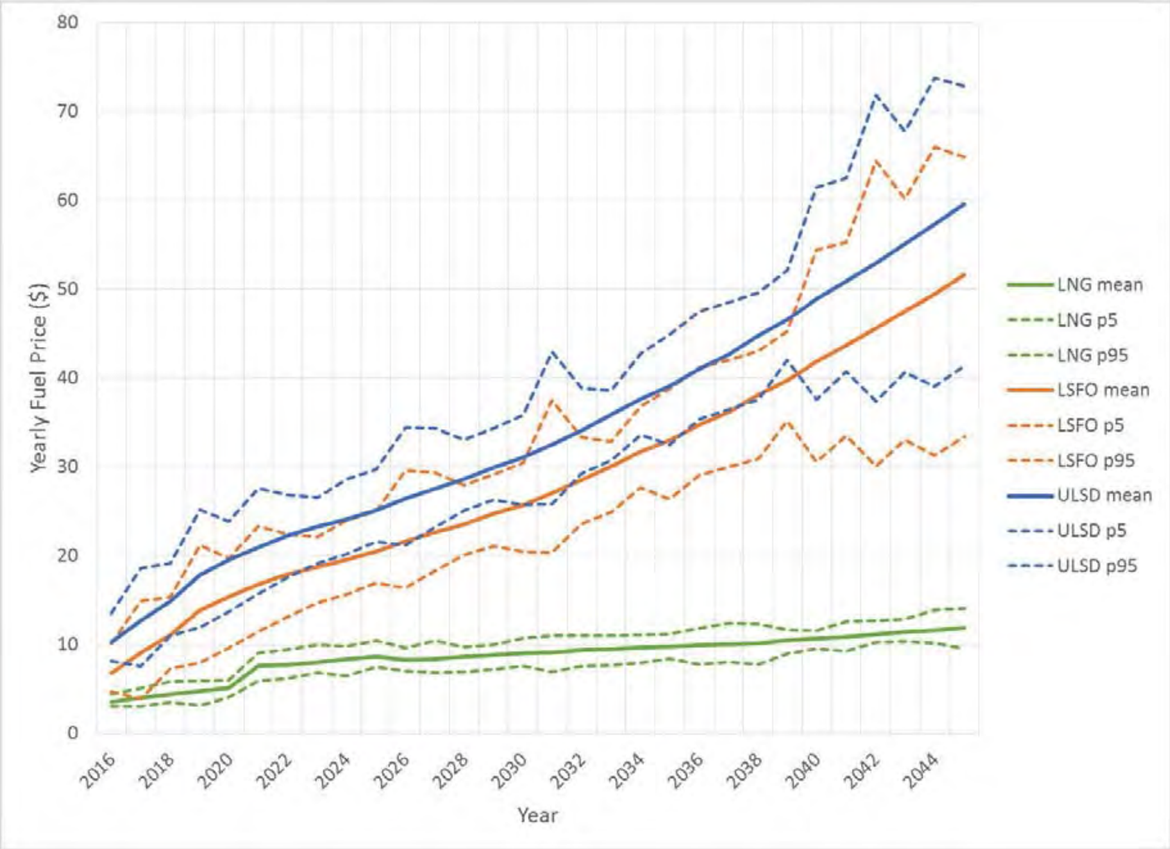


Figure 71: Shows simulated LNG, LSFO, and ULSD prices

8.1.2. Maui Validation

Validation plots for Maui weather and load are shown below.

Weather Validation

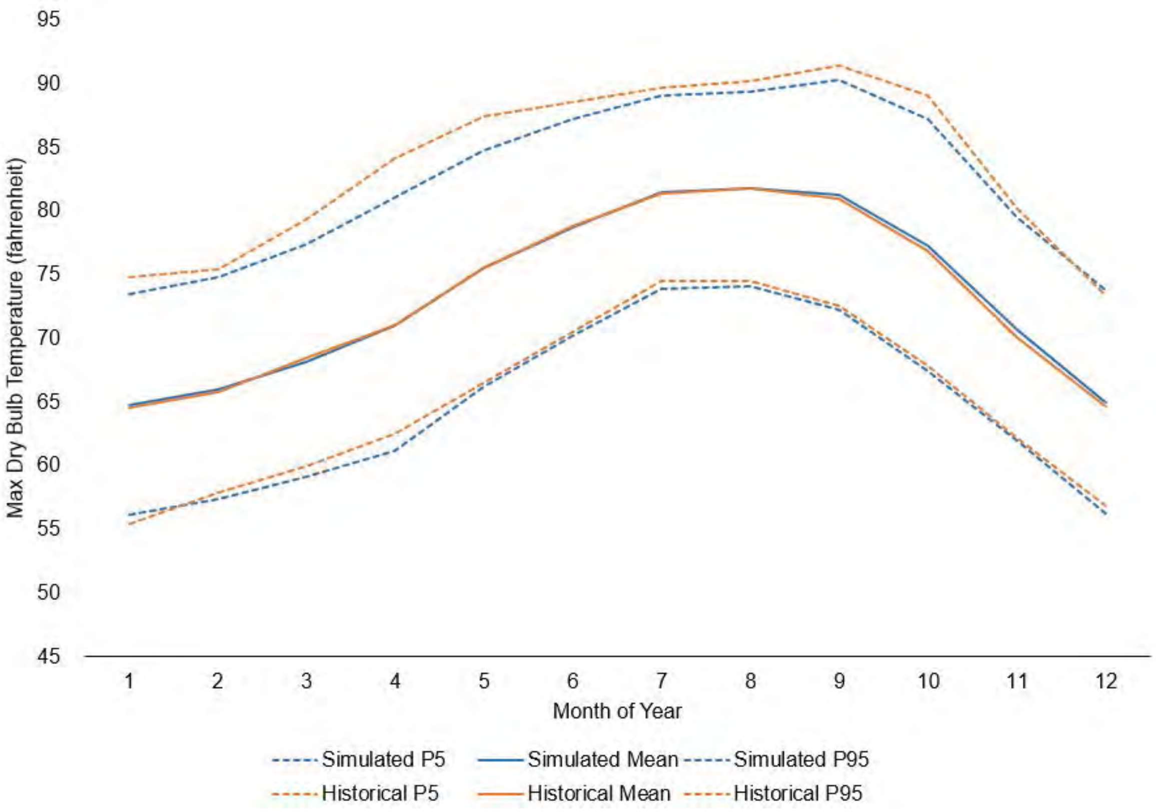


Figure 72: Shows that the historical weather data matches simulated weather data

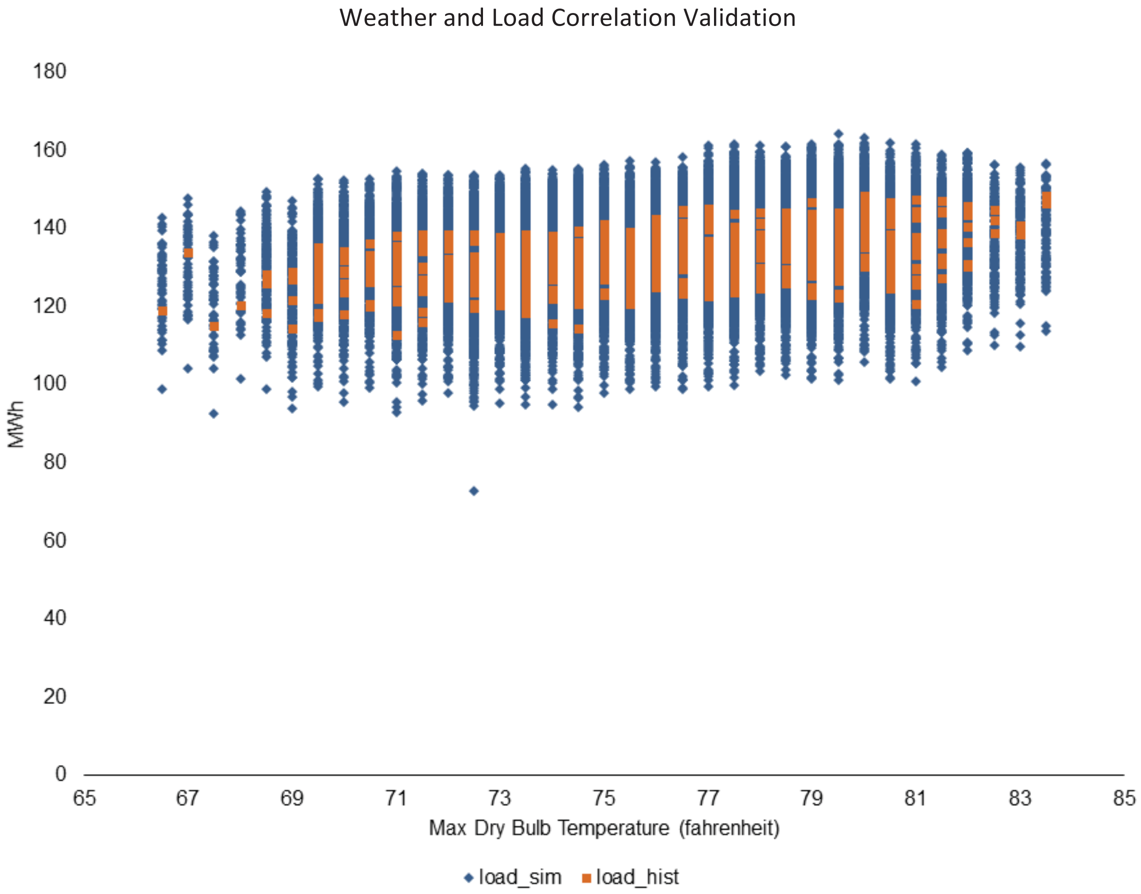


Figure 73: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

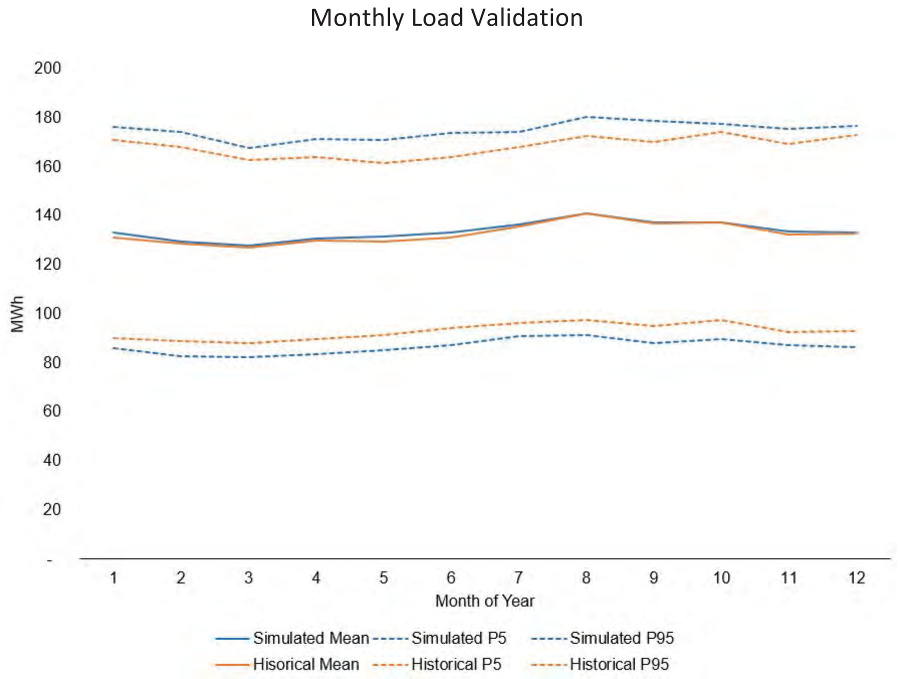


Figure 74: Shows that historical load data matches simulated load data on the monthly level

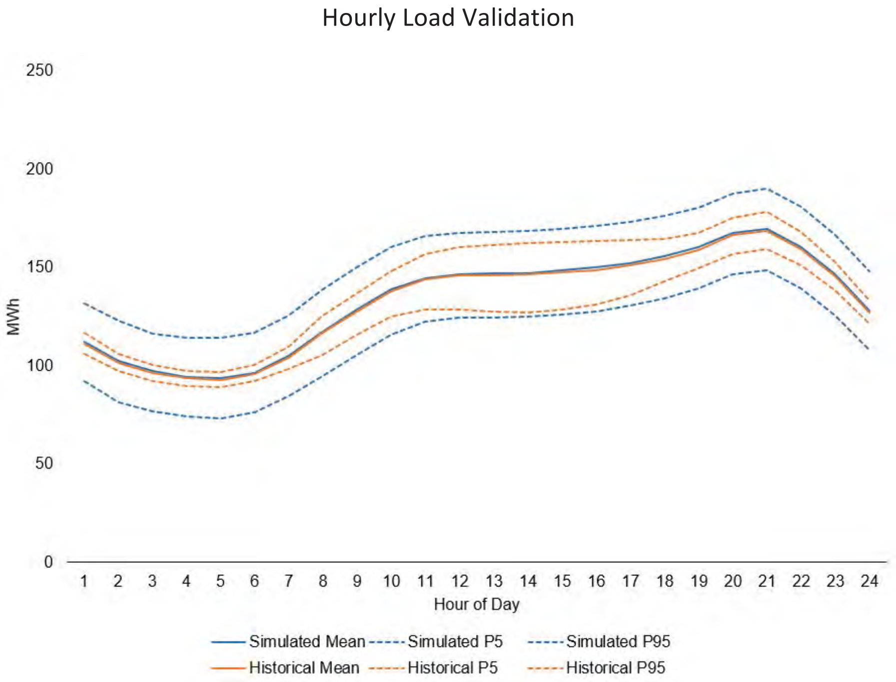


Figure 75: Shows that historical load data matches simulated load data on the hourly level

8.1.3. Hawaii Validation

Validation plots for Hawaii weather and load are shown below.

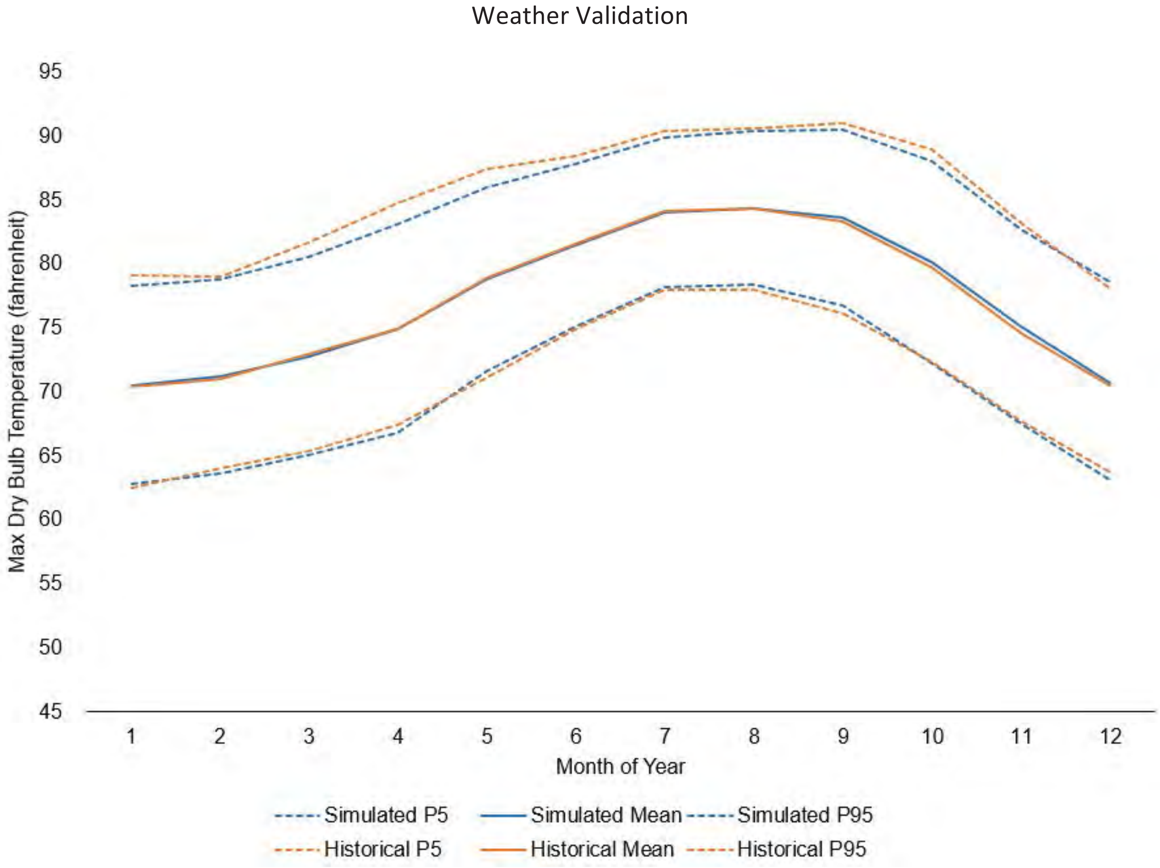


Figure 76: Shows that the historical weather data matches simulated weather data

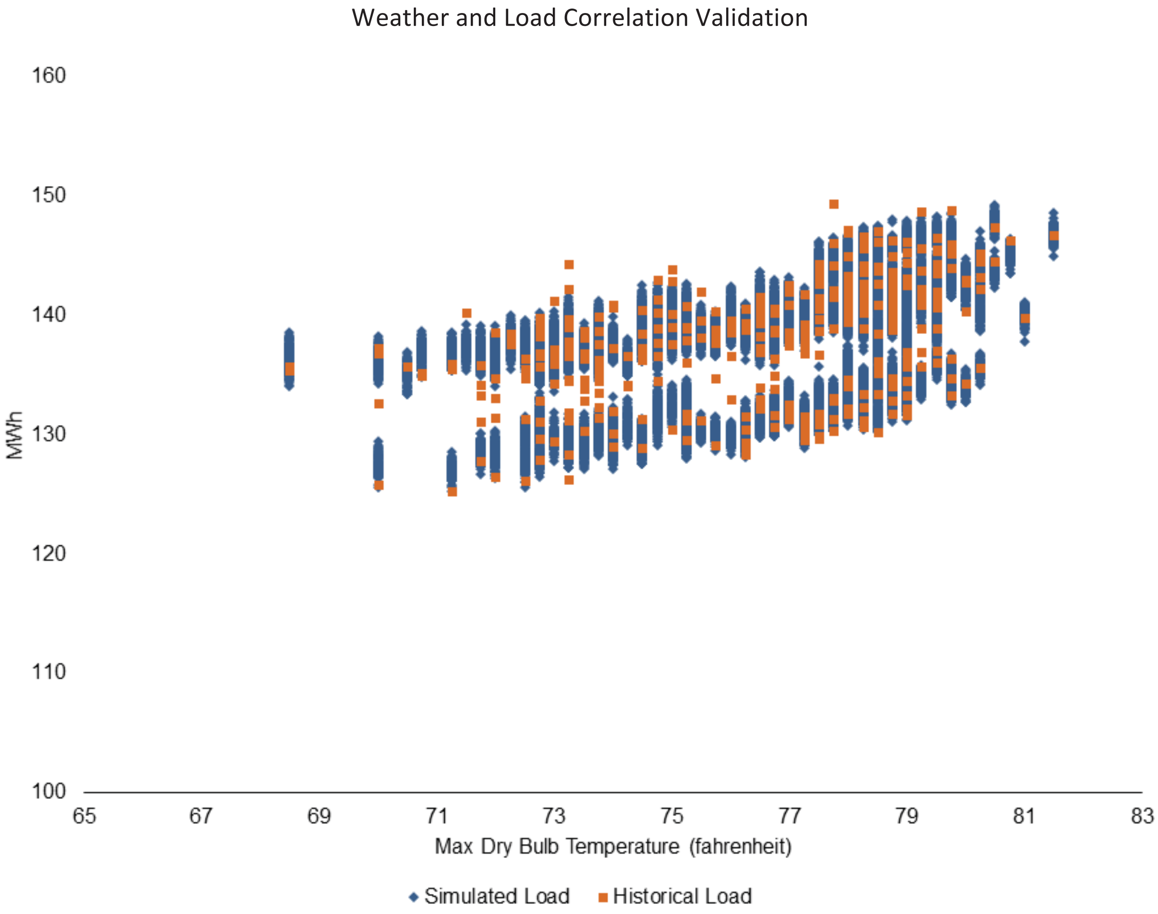


Figure 77: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

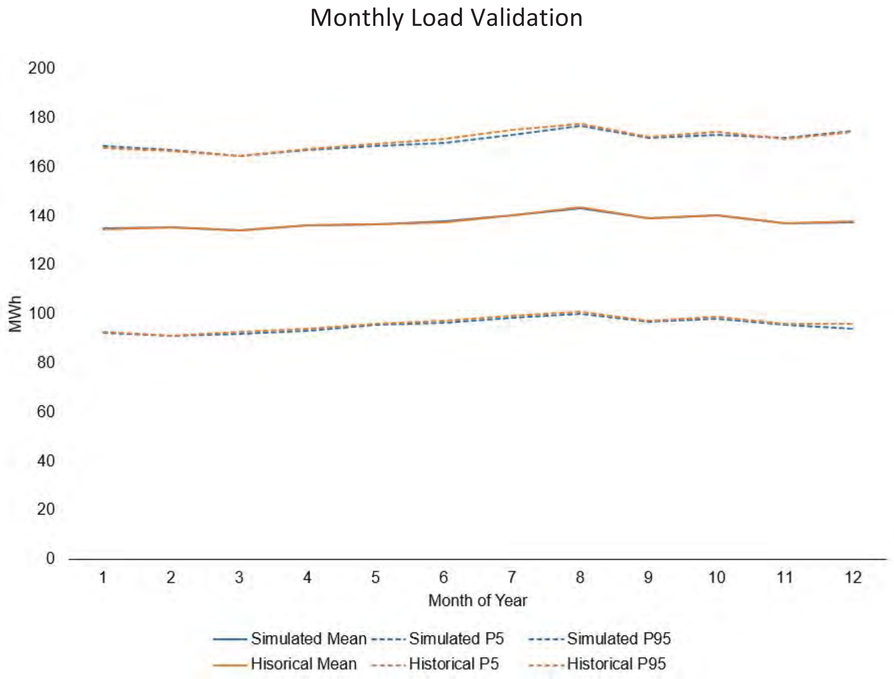


Figure 78: Shows that historical load data matches simulated load data on the monthly level

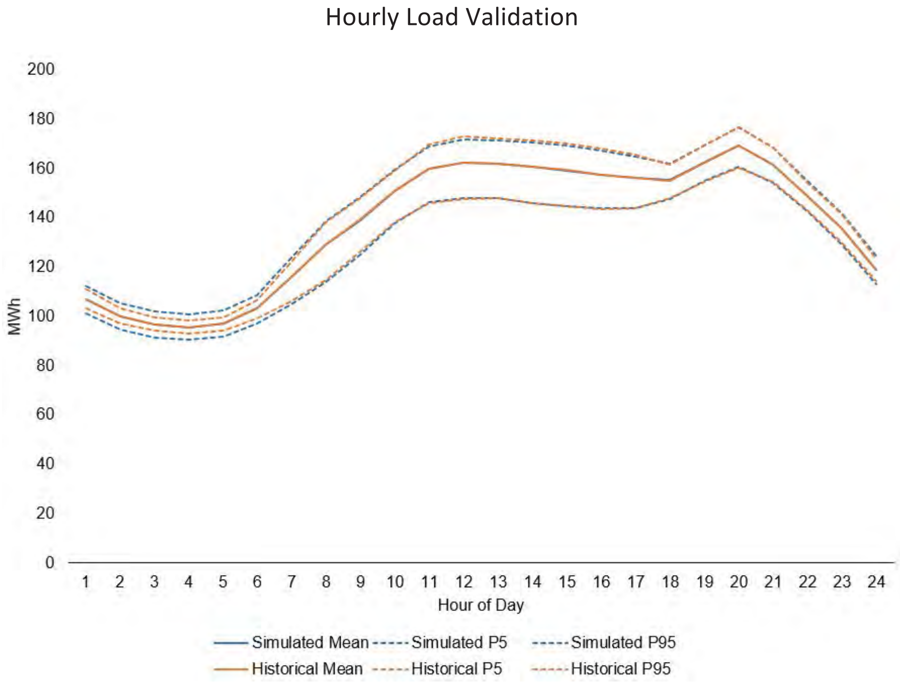


Figure 79: Shows that historical load data matches simulated load data on the hourly level

9. Addendum D: Data for System Flexibility Software

Minutely data for System Flexibility Software was collected or proxied for each island for Load, Utility Solar, Customer Solar, On-Shore Wind, and Off-Shore Wind. Each island has 3 themes, with separate forecasts and assumptions corresponding to each.

Oahu

Load	Minutely data for O'ahu net load was shared from January 2014 through October 2015. This load data has a small amount of DGPV netted out of it.
Utility PV	Minutely Data for KREP and KS2 were summed from January 2014 through October 2015.
Customer PV	Unitized minutely profile for DGPV for 2014, provided by HECO.
On-Shore Wind	Minutely data for Kahuku and Kawailoa were summed from January 2014 to October 2015. Starting in 2035, Kahuku and Kawailoa were summed with themselves lagged 28 days (one lunar cycle) to represent increased spatial diversity.
Off-Shore Wind	Two-Second data for HRD was aggregated to minutely in April, August, and December 2014 and used as a proxy for off-shore wind due to similar capacity factors and correlation to On-Shore wind.

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions, and Must-Run Thermal Generation Constraints. Load forecasts are constant between themes.

Hawaii

Load	HELCO shared a 2 second system load profile that was aggregated to minutely in April, August, and December 2014.
Utility PV	HELCO shared a 2 second PV profile that was aggregated to minutely in April, August, and December 2014.
Customer PV	HELCO shared a 2 second PV profile that was aggregated to minutely in April, August, and December 2014.
On-Shore Wind	Two-Second data for HRD and Tawhiri were aggregated to minutely in April, August, and December 2014.

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions. Load forecasts are constant between themes.

Maui

Load	HELCO System Load was used as a proxy for MECO System Load in April, August, and De 2014.
Utility PV	HECO PV data was used as a proxy for MECO Solar
Customer PV	HECO PV data was used as a proxy for MECO Solar
On-Shore Wind	HECO Wind Data was used as a proxy for MECO wind

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions. Load forecasts are constant between themes.

BLACK & VEATCH: DEMAND RESPONSE EVALUATION

Black & Veatch used its Adaptive Planning for Production Simulation (AP) model to evaluate Demand Response for the purpose of including Demand Response in the plans evaluated in support of the December 2016 update to the PSIP. The methodology, the AP model, and the plans incorporating DR are described elsewhere in this update. The following description focuses on the DR portfolio recommended for each island and the inputs that have a significant bearing on the recommendation.

The December 2016 update to the PSIP contains numerous plans. The DR evaluation was conducted using the post-April 2016 PSIP plan for each island, and the results were used in the production simulation and capacity planning models for the December 2016 PSIP update evaluation period. Grid service valuation was initially performed on a single plan per island; this guided the evaluation of DR amounts, costs, and the impact on system load shapes. Those initial plans per island were:

- *O‘ahu, Hawai‘i Island, and Maui:* Renewables without LNG
- *Lana‘i and Moloka‘i:* 100% renewable energy achieved in 2030

DR amounts, costs, and the impact to system load shapes were then evaluated on all post-April PSIP plans. In addition to those listed above, this included:

O‘ahu and Maui:

- Accelerated renewables without LNG
- Renewables without LNG and without new generation
- Renewables with LNG

Hawai‘i Island:

- Accelerated renewables without LNG
- Renewables with LNG

Later analyses involving both grid services valuing as well as defining DR amounts, costs, and the impact to system load shape were performed on the E3 plan:

- *O‘ahu:* E3 Plan with generation modernization. The E3 Plan was preliminarily examined, but due to concerns (identified in the Upcoming Capacity Need section below) was not fully evaluated.
- *Hawai‘i Island and Maui:* E3 Plan

Results of grid services valuing, updated for any differences developed following the post-April PSIP plan evaluations, will be documented in the February 2017 DR Application.

DR portfolios were provided to the PSIP modeling teams in the form of spreadsheets with sufficient detail to allow full, 8,760 hour/year incorporation of DR. The DR portfolio spreadsheets were specific to each island and each plan evaluated. Each spreadsheet contained the following tabs:

Buildout Modification: This tab represents the grid-scale assets that can be avoided or deferred based on the addition of DR resources. When evaluating the removal of firm generation on O'ahu, additional Loss of Load Probability modeling is undertaken to confirm that the system still meets acceptable system reliability metrics.

Spin: The spin tab represents the amount of spin equivalent that DR regulating reserve assets are capable of providing in each hour of the study period, following allocation to FFR and load shift. Customer batteries are a critical contributor to DR's ability to provide regulating reserves. The current assumption for regulating reserves from customer batteries is that batteries are able to provided regulating reserve up based on the amount of charging currently occurring (i.e., the charge can be interrupted).

Load Modification Profile: This tab represents the incremental change to demand resulting from DR assets for each hour of the study period. These DR assets seek to reduce peak loads, utilize curtailment and in general allow firm generating units to operate at more economic heat rates.

Modified Demand Profile: The Modified Demand Profile tab represents the modified gross demand after the effects outlined in the Load Modification Profile are taken into account. This profile also details every hour of the study. This tab provides an easy plug and play input to other models that are already incorporating an unmodified gross load profile.

In addition to evaluating DR, Black & Veatch performed Loss of Load Probability (LOLP) modeling for certain O'ahu cases to help confirm the adequacy of supply associated with those cases.

Demand Response Plan – O‘ahu

The current plan for O‘ahu’s demand response portfolio is to reduce the size of the contingency battery via FFR DR, load shift via pricing programs and provide regulating reserves.

System Characteristics – O‘ahu

Current Generation

Baseload Generation

- 6 Steam Units at Kahe (650 MW total)
- 2 Steam Units at Waiau (83 MW and 86 MW for Waiau 7 and 8 respectively)
- 1 Combined Cycle Unit (208 MW)
- 1 Coal Unit (189 MW)
- 1 Waste Fired Unit (68.5 MW)

Intermediate Generation

- 4 Steam Units at Waiau (200 MW for Waiau units 3 through 6)

Peaking Generation

- 2 Combustion Turbines at Waiau (103 MW)
- 1 Dual Fuel Fired Combustion Turbine (130 MW on diesel and 115 on biodiesel)

Renewable Generation

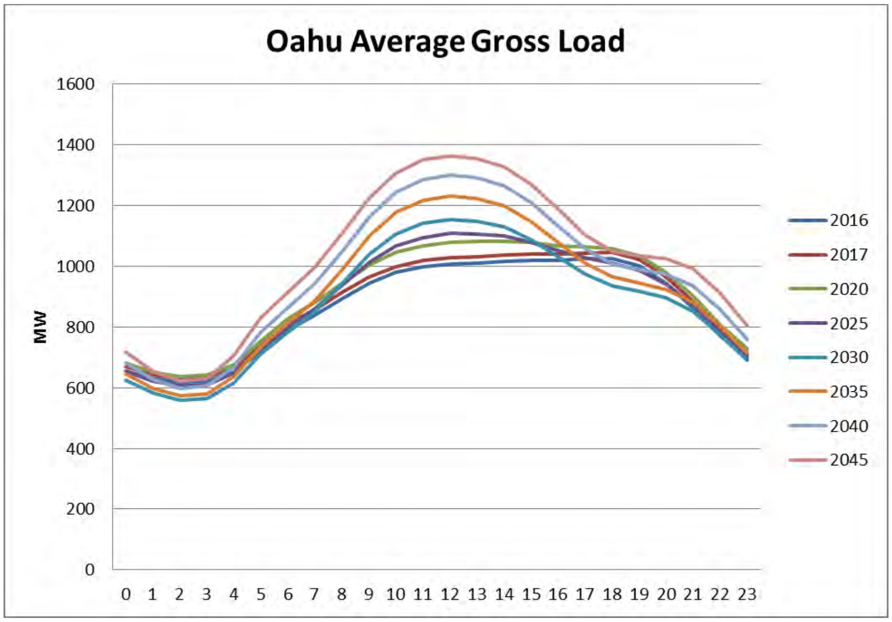
- 3 Wind Farms-Kahuku, Kawailoa Wind and Na Pua Makani (30 MW, 69 MW and 24 MW respectively)
- 3 Solar Farms-KSEP, KREP and Kalaeloa Solar 2 (5 MW, 5 MW and 1 MW respectively)

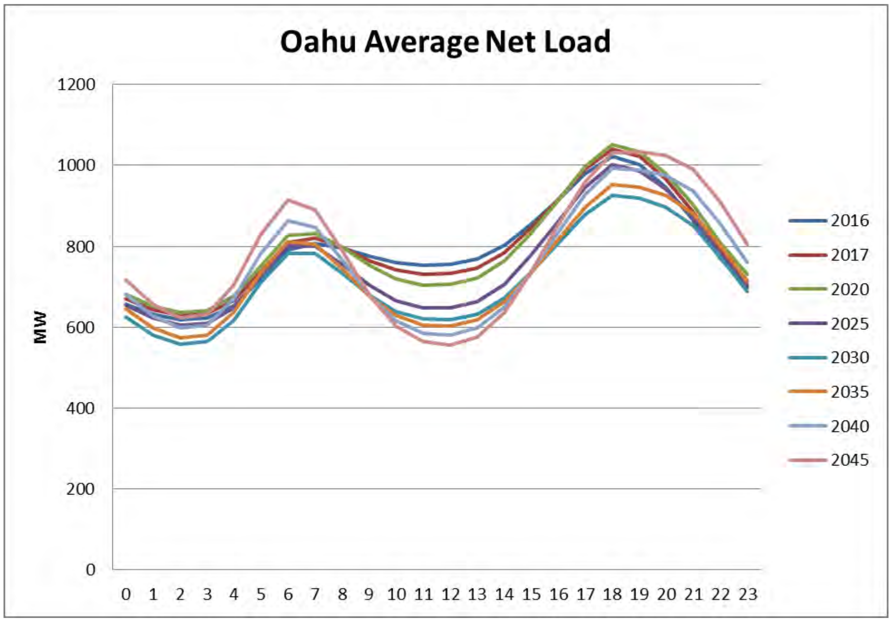
Distributed Generation

- DG-PV- roughly 400 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis. There is a significant change in the effective shape of the load over time that has resulted in an increasing midday load without a significant change to the rest of the day.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Upcoming Capacity Need

The island of O‘ahu has over 1700 MW of firm generation currently online for a system that currently has an annual peak load of roughly 1170 MW. As a result, the island currently has a reserve margin of around 45%. While the system does have excess capacity currently, the speed of the system is lacking. Only two units can turn on in less than 40 minutes. The baseload generation on the island is both slow and relatively inefficient compared to new technologies. The current plan is to retire Waiau units 3 through 6 in all plans (except the E3 Plan, addressed below). These units will be effectively replaced with various ICE units installed at military bases. These new units will provide speed to the system as well as additional reliability to the system as a whole and to the bases where they are located. Plans also include the future retirements of all Kahe units with the intent of replacing the units with more efficient and fuel flexible one on one combined cycle units.

The E3 Plan, as currently defined, may have difficulty meeting the capacity needs of O‘ahu. The E3 Plan calls for the retirements of AES, Waiau 3, Waiau 4, Waiau 5, Waiau 6, Waiau 7, Waiau 8, Kahe 1, Kahe 2, Kahe 3, and Kahe 4 by 2022 with only 426 MW of load shifting battery added to the system. With nearly 900 MW of firm capacity retired, even with customer batteries and load shifting DR, production simulation and LOLP modeling indicate that the system will likely suffer significant unserved demand. Due to the capacity concerns associated with the E3 Plan as currently defined, we have deferred evaluation of DR for this plan until such time as the plan can be re-constructed to more closely meet capacity needs.

High Solar Penetration

The electric system on O‘ahu has limited on-shore wind potential and significant solar potential. With off-shore wind being expensive and given the aggressive renewable targets set by the state, solar will be the primary source of renewable generation on the island. There is already a significant amount of rooftop solar on the island and all of the plans will add additional grid-scale PV projects to the island. The E3 Plan with generation modernization adds nearly 1800 MW of grid-scale solar while the Renewables without LNG plan will add 840 MW. In the near-term, both plans will install nearly 140 MW of grid-scale solar via the Waiver PV solar farms.

Off-Shore Wind Penetration

As the electric system on O‘ahu is saturated with solar energy, the need for nighttime renewable generation will drive the installation of significant off-shore wind assets. While off-shore wind has high capital costs, the wind quality is much higher than on-shore assets making it the more attractive choice. All plans install off-shore wind assets. The E3 Plan with generation modernization targets an installation of 200 MW in 2025. The Renewables without LNG plan includes two 400 MW installations in 2040 and 2045, respectively.

Load Shifting Battery

With the staggering amount of solar energy being installed on the island, the need for load shifting batteries is critical. Load shifting batteries will both reduce curtailment of free energy and reduce fuel usage. 300 MW of load shifting batteries are scheduled to be installed in 2030 for the Renewables without LNG plan. The E3 Plan with generation modernization targets installation of 2700 MW through 2045. These batteries could represent a potential opportunity for deferment via DR as they provide the same services. Both the Companies and E3 teams incorporated the load shifting capabilities of DR into their buildout plans. Thus, the sizing of the load shifting batteries accounts for the load shift ability provided by DR.

Regulating Battery

The Renewables without LNG plan for O‘ahu installs a 100 MW regulating battery in 2020. The E3 Plan with generation modernization does not include a regulating battery. This battery would provide significant value to the grid providing quick ramping as well as regulation. Regulation from a battery instead of online generation can provide significant fuel savings. This battery is probably not a candidate for deferral via DR as it provides regulation at all hours of the day and is relatively less expensive than other potential deferral options.

Contingency Battery

Absent of DR, O‘ahu plans install a 120MW contingency battery in 2019. Following the expected retirement of AES, this battery will bring the system into TPL-001 compliance meaning the system should no longer rely on load shedding to restore system stability following a contingency event. While the battery is targeting installation in 2019, the retirement of AES is not expected until 2022. This means a full trip of AES in the middle of the day could still result in the need to load shed to restore the system.

The O‘ahu system’s need for FFR peaks during the middle of the solar day for two main reasons. The first reason is that significant solar generation allows for the de-commitment of firm units to minimize curtailment. A side implication to de-committing units is that the kinetic energy of the system will be at its lowest during this period of the day. At the same time, the contingency need is exacerbated during the middle of the day due to 55 MW of legacy inverters connected to DG-PV. These inverters will trip if the system frequency drops below 59.3 Hz. Because the need for FFR peaks in the middle of the day, the battery is effectively oversized in non-solar hours. This represents an opportunity for demand response to downsize the contingency battery by providing mid-day FFR.

DG-PV Growth

DG-PV is expected to grow to about 1400 MW over the next thirty years based on the latest market forecast. The High DG-PV forecast sees over 2,100 MW of DG-PV possibly being added to the system. Regardless of the forecast being examined there will be significant curtailment of renewables in the future on the island without Demand Response programs and significant load shifting batteries.

Customer Battery

Customer battery populations grow rather dramatically towards the end of the study reaching about 180 MW by 2030 and 580 MW by 2045.

Demand Response Potential

Demand response potential for FFR is 30 MW in 2019 allowing the downsizing of the contingency battery. Pricing program potential for non-battery demand response end devices grows quickly from about 40 MW in 2019 to 90 MW in 2030. Potential for regulating reserves is about 15 MW.

Demand Response Implications – O‘ahu

There are a few natural candidates for deferral on the island in particular a portion of the load shifting and contingency batteries. Load shifting in combination with FFR looks to be a promising, complementary opportunity for DR as the need for FFR load reduction will occur in the middle of the day while the need for load shift load reduction will occur on the evening peak. Because of the high amount of solar energy there is a natural benefit for DR to provide load shifting into the solar peak and away from the evening peak load. With the emphasis on load shift and FFR, there is still potential for regulating reserve to be provided by end devices not providing FFR during the middle of the day.

Demand Response Plan – Hawai‘i Island

The current plan for the demand response portfolio on Hawai‘i Island is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Hawai’i Island

Current Generation

Must-Run Generation

- 1 Combined Cycle Unit- Keahole (53.5 MW)
- 3 Steam Units - Hill 5, Hill 6 and Puna Steam (13.5 MW, 20 MW, and 15.5 MW respectively)
- Geothermal – PVG (30 MW must take on peak, 27 MW must take off-peak, 38 MW dispatchable)

Intermediate Generation

- 1 Combined Cycle - HEP (60 MW)
- 1 Simple Cycle Gas Turbine- Puna CT3 (19MW)

Peaking Generation

- 2 Simple Cycle Gas Turbines - Kanoelehua CT1 and Keahole CT2 (10MW and 14 MW respectively)
- 14 Small Diesel Generators (28 MW total)

Renewable Generation

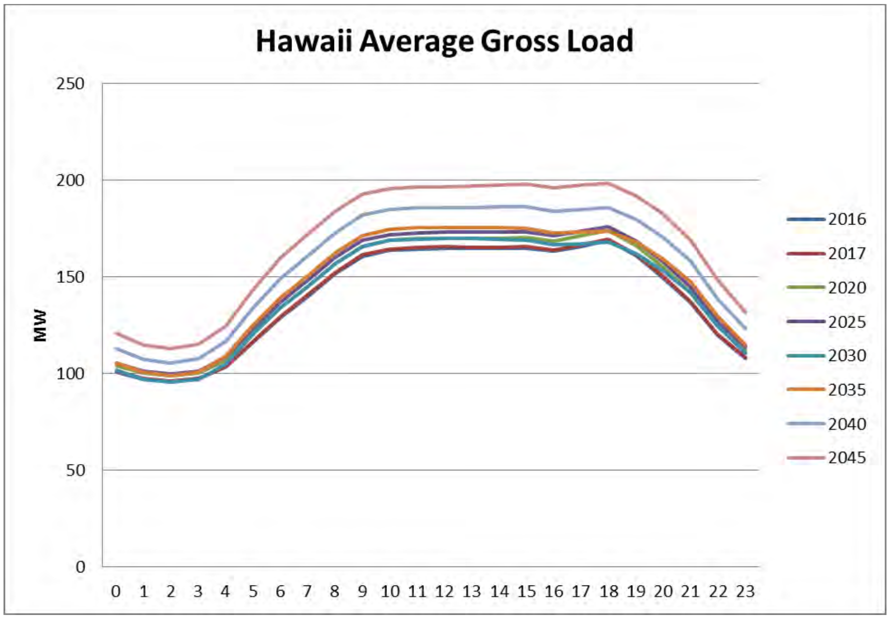
- 2 Wind Farms - Tawhiri and HRD (20.5 MW and 10.5 MW respectively)
- 1 River of River Hydro Unit - Wailuku (12.1 MW)

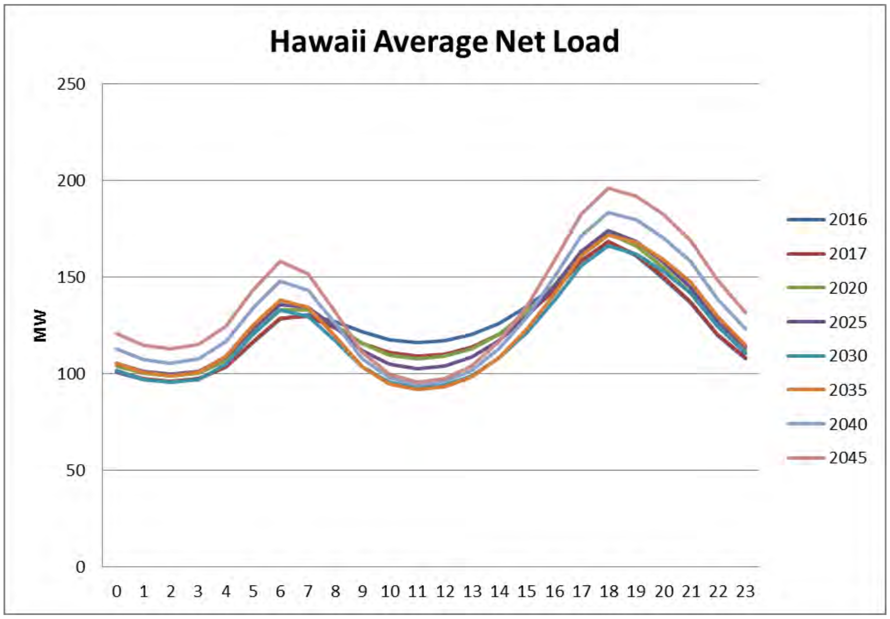
Distributed Generation

- DG-PV - 85–90 MW currently

Load Profile Characteristics

The system is an evening peak system with a smaller morning bump in load on a net basis. There is no significant change in the effective shape of the load over time but there is a general increase in energy demand over time.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Hawai‘i has over 270 MW of firm generation for a system that currently has an annual peak load of roughly 190 MW. As a result, the island has excess capacity and a reserve margin of well over 40%. Current plans do not include any new units added strictly for capacity, although new firm renewable units help meet capacity while ensuring grid stability in the non-E3 plans. The E3 Plan on Hawai'i may be short on capacity in the near-term following the retirement of Hill 5, Hill 6 and Puna Steam in 2020. Because utilization of demand response programs does not avoid new generation, the savings found by DR will be operational.

High Wind Penetration

While the system has about 31 MW of onshore wind currently, most plans will increase that number significantly. The Renewables without LNG plan is scheduled to add 20 MW in 2020 and an additional 20 MW in 2030. The E3 Plan will add 100 MW of wind to the system with 70 MW installed by 2022. Both existing wind farms have relatively unfavorable contracts from the perspective of incentivizing a reduction in their curtailment. The energy provided is charged at the relatively high avoided cost rate and there is currently no cost to curtail energy that cannot make its way on to the system. These contracts are set to expire in 2021 for HRD and 2027 for Tawhiri.

Current and Future Geothermal

Currently, the island of Hawai‘i gets about 20% of its energy from the geothermal plant, PVG. The Renewables without LNG plan includes an additional 40 MW of geothermal energy on the island by 2030. These new geothermal units will have very low variable costs and reasonable ability to turn down in response to heavy wind and solar production. The E3 Plan does not include additional geothermal generation.

Retiring Must Run Units

In the Renewables without LNG plan new geothermal units and a new 20 MW Biomass unit will come online as must run units and replace the aging must-run steam units. This switch in must-run units maintains the system security as renewable penetration increases while still replacing oil burning generation with firm renewable units. The E3 Plan retires Puna Steam, Hill 5, and Hill 6 all in 2020 but without replacing them with other firm generation.

Contingency Battery

Although a 15 MW contingency battery installation is planned in 2019, using FFR DR to downsize this battery will not result in the most cost effective DR portfolio. On O‘ahu there is a much greater FFR need in the middle of the day due to the 55 MW legacy DG-PV that will trip with a major system disturbance. On Hawai’i Island this is not the case as the need for FFR is much more constant throughout the day. Therefore if some portion of the contingency battery was deferred by FFR DR then the system would need to reserve those end devices throughout the day, including during the evening peak hours. Because these end devices would be reserved for FFR load reduction services during the evening peak, they could not be used to reduce load as part of a load shifting scheme. The decision then becomes a tradeoff between the more attractive economic choice - load shifting - versus contingency battery reduction.

In addition to the economic considerations for choosing load shifting DR over FFR for Hawai‘i Island, there are also significant security concerns with utilizing DR FFR on Hawai‘i Island. Unlike O‘ahu, Hawai‘i Island may still utilize under frequency load shedding to maintain system security in response to large system disturbances. Because DR FRR MWs will be on the same circuits that could be subject to load shedding this may materially affect how much load exists on each kicker block. FFR DR can introduce uncertainty as to the amount of load shed available which could in turn make a relatively small system disturbance larger.

DG-PV Growth

DG-PV is expected to grow to about 150 MW over the next thirty years based on market forecast used in the April 2016 update to the PSIP. The High DG-PV forecast sees over 460 MW of DG-PV added to the system. Regardless of the size of the forecast there will be significant curtailment of renewables in the future without Demand Response programs or significant load shifting batteries.

Customer Battery Installations

Customer battery populations grow rather dramatically towards the end of the study reaching about 20 MW by 2030 and 60 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows from about 4 MW in 2019 to 8 MW in 2030. Potential for regulating reserves is about 8 MW.

Demand Response Implications – Hawai‘i Island

Hawai‘i Island has a difficult resource mix to facilitate a cost effective demand response program, especially in the near term. With no assets added strictly for capacity, TOU and Real Time Pricing programs will have to be cost effective based strictly on operational savings. With the structure of the PPA agreements with the current wind farms and hydro plant, uncurtailing renewables can increase the percentage of renewables on the system but not result in cost savings. As those contracts expire and new contracts are negotiated this can change quickly. Current modeling assumptions switch to NREL fixed and variable cost pricing after the current contracts end. NREL pricing structures incentivize increased renewable utilization through high fixed costs and minimal to zero variable cost. Because Hawai‘i Island's current requirements are not dedicated to the TLP-001 standard that O‘ahu is planning to attain, it is hard to prove an avoided cost savings for an FFR DR program. When PPA contracts expire and biodiesel fuel switch occurs DR will find significant value in load shifting and regulating reserve programs based on a reduction in fuel usage and subsequent fuel cost savings.

Demand Response Plan – Maui

In the near term, demand response appears to be an effective means to assist in meeting capacity need. In addition, Maui's demand response portfolio will obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Maui

Current Generation

Baseload Generation

- 4 Oil Fired Units at Kahului (32.5 MW total)
- 1 Combined Cycle Ma‘alaea DTCC1 (53 MW)

Intermediate Generation

- 8 Oil Fired Units at Ma‘alaea (71 MW total)
- 1 Combined Cycle Ma‘alaea DTCC2 (53 MW)

Peaking Generation

- 7 Oil Fired Units at Ma‘alaea (23.5 MW total)

Renewable Generation

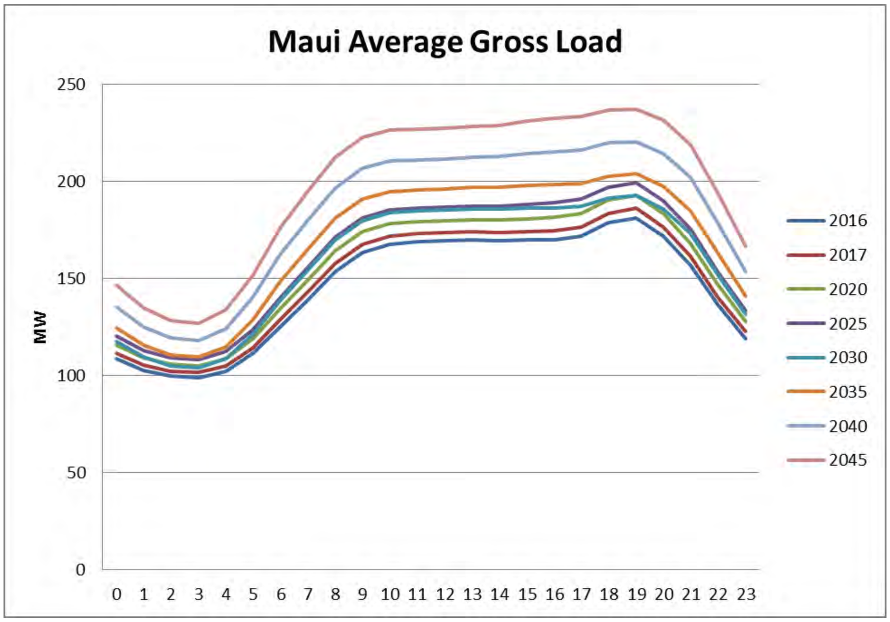
- 3 Wind Farms - Auwahi Wind Energy, Kaheawa Wind Power and Kaheawa Wind Power 2 (21 MW, 30 MW and 21 MW respectively)
- 1 River of River Hydro Unit - Makila Hydro (0.5 MW)
- 1 Solar Plant - South Maui Renewable Resource (5.47 MW starting 2017)

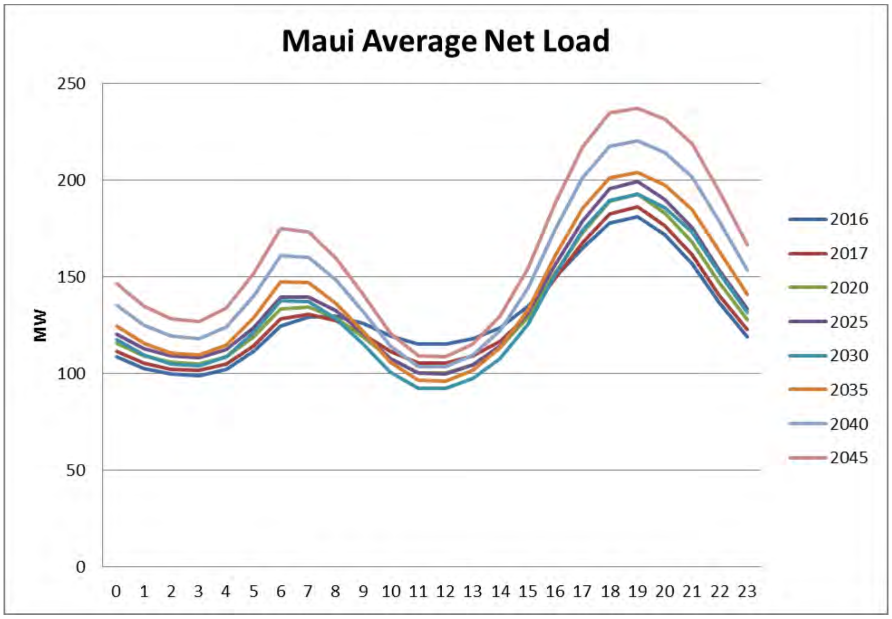
Distributed Generation

- DG-PV - 90 MW currently

Load Profile Characteristics

The system is an evening peak system with a smaller morning bump in load on a net basis. There is no significant change in the effective shape of the load over time but there is a general increase in energy demand over time.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Upcoming Capacity Need

The island of Maui has over 237 MW of firm generation online for a system that currently has an annual peak load of roughly 200 MW. As a result, the island has a reserve margin of around 18%. Maui's limited capacity is at least partially due to the pending retirement of the HC&S bagasse burning unit in addition to growing electrical demand. As a result, two units, Kahului 1 and Kahului 2, have recently been reactivated. Following the planned retirement of all four Kahului units in 2023, the system will again have a need for capacity. The current plans include the installation of firm biomass and geothermal, load shifting storage, and new ICE units. Because the island of Maui does have a capacity need it is likely that DR will be able to find some capital savings from the downsizing or deferral of new assets.

The E3 case on Maui may be short on capacity in the 2045 following the retirement of Maʻalaea units 4 through 13.

High Wind Penetration

The electric system on Maui has 72 MW of wind currently with aggressive plans to expand further. The Renewables without LNG plan includes the installation an additional 90 MW of wind in 2020. The E3 Plan includes 60 MW of new wind in 2020. With over 110 MW of wind on the island in 2020 in all themes, the transition to real time pricing will be critical to unlock the full benefits of load shifting. Unlike solar assets which only generate energy during the middle of the day, wind energy can be generated all day. This potential to generate at any time of the day will require a more dynamic pricing program to enable more wind energy to make it on the grid. However, a more dynamic pricing program will only be as effective as the ability to forecast wind generation in the future. Our model currently functions with perfect knowledge of future wind variability and might understate the uncertainty related to forecasting wind generation.

Current and Future Geothermal

Currently, there are no geothermal assets on the island of Maui. All plans install 40 MW of geothermal units. The Renewables without LNG plan targets installing 40 MW in 2030 while the E3 Plan targets an installation date of 2040. These new geothermal units will have very low variable costs and reasonable ability to turn down in response to heavy wind and solar production.

Current and Future Biomass

There is just one biomass plant on Maui, HC&S, and that plant is scheduled to retire in 2017. The Renewables without LNG plan includes the installation of 20 MW of biomass in 2022 and an additional 40 MW in 2040. The E3 Plan installs 40 MW of biomass in 2022. These units will be baseload and provide some turndown to allow non-firm renewables to make it on to the system.

Retiring Must Run Units

All Kahului units are scheduled to retire in either 2022 or 2023. Firm renewables will replace these units starting with the biomass unit being installed in 2022 and continuing with the other biomass and geothermal installations.

DG-PV Growth

DG-PV is expected to grow to about 200 MW over the next thirty years based on market forecast used in the April 2016 update to the PSIP. The High DG-PV forecast sees over 435 MW of DG-PV being added to the system. Regardless of the forecast being examined there will be significant curtailment of renewables in the future on the islands without DR or significant load shifting batteries.

Customer Battery Installations

Customer battery populations grow stead towards the throughout the study reaching about 30 MW by 2030 and 68 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows quickly from about 6 MW in 2019 to 16 MW in 2030. Potential for regulating reserves is about 20 MW.

Demand Response Implications – Maui

Maui is very similar to Hawai‘i Island in terms of the DR portfolio with some notable exceptions. While Hawai’i has PPA agreements that make reducing wind curtailment less economical in the immediate term, Maui does not have those same contract structures. The dynamic nature of real time pricing will be necessary to capture the potential wind resources on Maui. With significant renewable resources come increased regulating requirements, so regulating reserves provided by DR should contribute high value to the island. Because Maui is not targeting, at this time, to meet the TLP-001 standard that O’ahu is pursuing, it is hard to prove an avoided cost savings for an FFR program. During Maui’s capacity need it is likely that DR will serve to displace a load shifting battery or other asset by providing the same services. Even absent capital avoidance, DR is expected to provide significant value in load shifting and regulating reserve programs from a reduction in fuel usage.

Demand Response Plan – Lana‘i

The current plan for the demand response portfolio on Lana‘i is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Lana‘i

Current Generation

Baseload Generation

- 2 ICE Units (4.4 MW total)

Intermediate /Peaking Generation

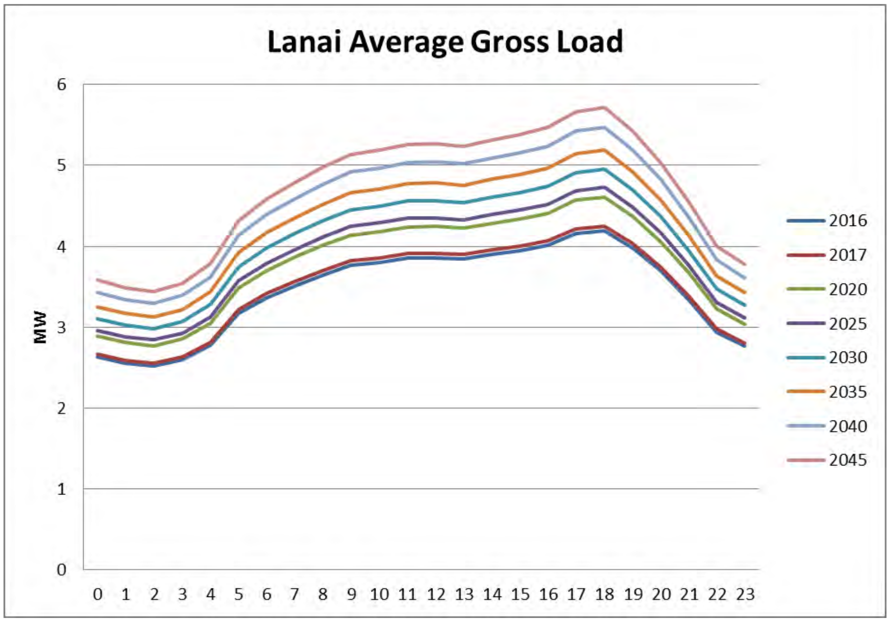
- 6 ICE Units (6 MW total)
- 1 CHP (0.83 MW)

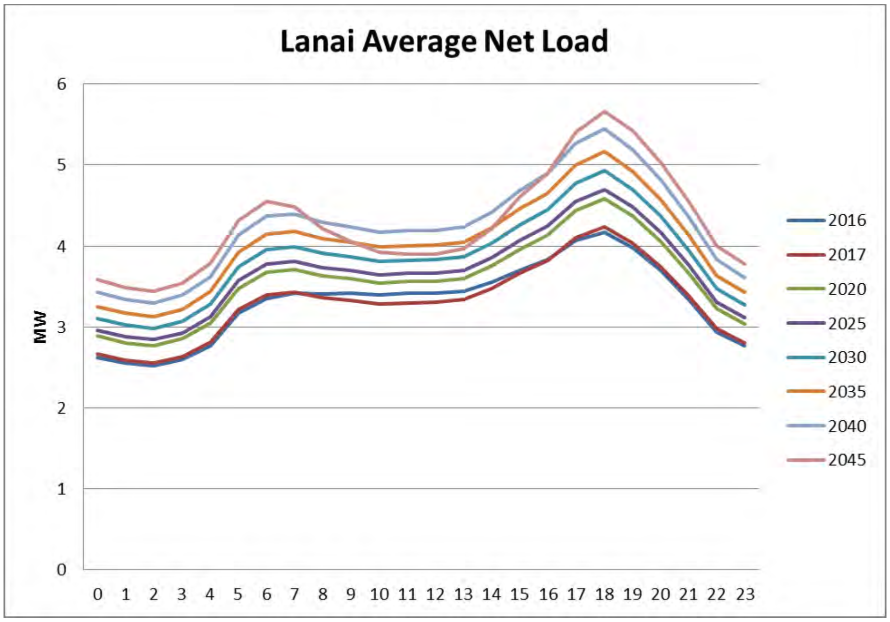
Distributed Generation

- DG-PV - roughly 0.8 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Lana‘i has about 11.2 MW of firm generation compared to a current peak load about 5.2 MW. Plans for the island do not contain new firm unit installations.

Solar Penetration

Lanaʻi has significant solar potential that far exceeds the need of island. However, plans do not include grid-scale solar and instead focus on grid-scale wind.

Wind Penetration

Lanaʻi has significant wind potential. All plans for the island include at least 4 MW of wind installed in 2020.

DG-PV Growth

DG-PV is expected to grow to about 2.2 MW over the next thirty years based on the latest market forecast. There will be curtailment of renewables in the future on the island without DR, particularly once the wind generation is added to the island in 2020.

Customer Battery Installations

Customer battery populations grow slowly throughout the study reaching about 0.17 MW by 2030 and 0.7 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows from about 0.05 MW in 2019 to 0.1 MW in 2030. Potential for regulating reserves is about 0.04 MW.

Demand Response Implications – Lanaʻi

With high renewable penetration targeted on the island, DR will find value in load shifting to take advantage of curtailed energy. Because the island is operated primarily with 8 ICE units there is minimal operational savings associated with load shifting that does not capture curtailment. The high renewable penetration creates a need for regulating reserves that can reduce curtailment by de-committing units online to serve regulation.

Demand Response Plan – Molokaʻi

The current plan for Molokaʻi's demand response portfolio is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Molokaʻi

Current Generation

Baseload Generation

- 3 ICE Units (6.6MW total)

Intermediate /Peaking Generation

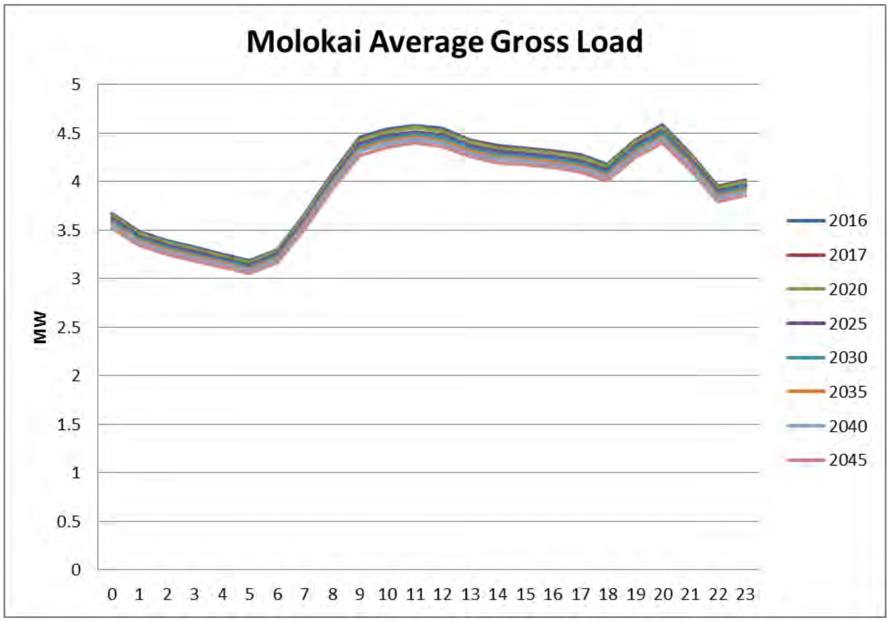
- 6 ICE Units (6.4MW total)
- 1 Combustion Turbine (2.2 MW)

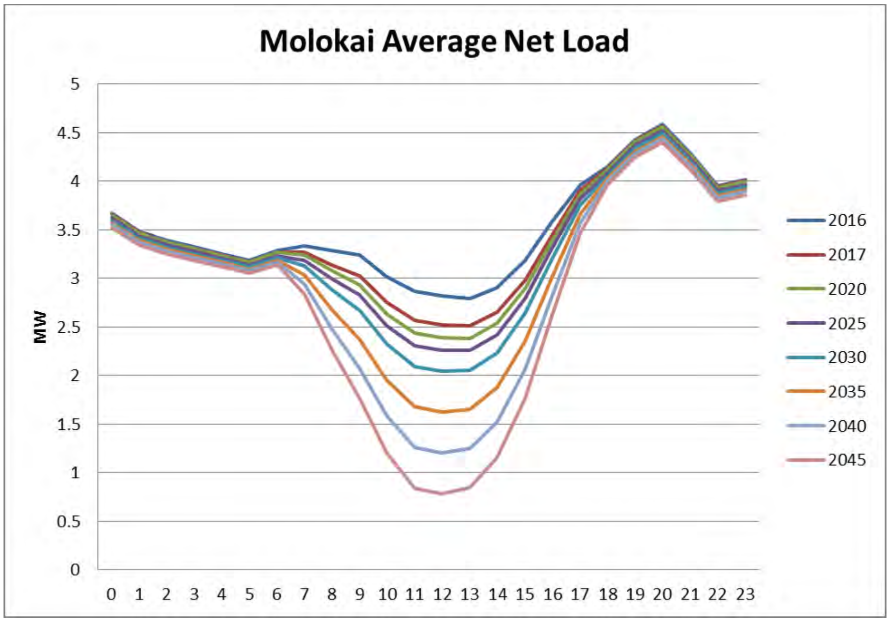
Distributed Generation

- DG-PV- roughly 2.5 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Moloka‘i has about 15 MW of firm generation compared to a peak load about 5.5 MW. There is likely no need for additional firm generation and plans for the island do not contain new firm unit installations.

Solar Penetration

Moloka‘i has significant solar potential that far exceeds the need of island. However, plans do not include grid-scale solar and instead focus on grid-scale wind.

Wind Penetration

Moloka‘i has significant wind potential. All plans for the island include at least 4 MW of wind installed in 2020.

DG-PV Growth

DG-PV is expected to grow to about 5.5 MW over the next thirty years based on the latest market forecast. There will be significant curtailment of renewables in the future on the island without DR especially following the wind installation in 2020.

Customer Battery Installations

Customer battery populations grow rather dramatically towards the end of the study reaching about 1.3 MW by 2030 and 5 MW by 2045.

Demand Response Implications – Moloka‘i

With high renewable penetration targeted on the islands, DR will find value in load shifting to take advantage of curtailed energy. Because the island is operated primarily with 9 ICE units there is minimal operational savings associated with load shifting that does not capture curtailment. High renewable penetration on the island creates a need for regulating reserves which can reduce curtailment by de-committing units online to serve regulation.

Q. Customer Exit Economic Analysis

Pages Q-2 through Q-4 contain confidential and/or proprietary information, and are designated as "restricted information" to be provided only to the Commission and the Consumer Advocate, and not to be distributed to any other party or participant to this proceeding or its representatives.